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Environmental Implications of Electric Utility Supply Plans, 1978-2000

California Energy Commission
Sacramento

May 80

U.S. Department of Commerce
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STAFF REPORT

MAY 1980

ENVIRONMENTAL IMPLICATIONS OF ELECTRIC UTILITY SUPPLY PLANS 1978–2000

California Energy Commission

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Tom MacDonald.

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The report presents the results of the environmental assessment of the current electricity supply plans of the California utilities. Major areas of assessment are construction and operation of electric generation facilities, including air quality, land use, and solid waste disposal. Maps in this report show the locations of utility proposed generation facilities and potential siting areas for additional facilities. It also discusses methods used to designate potential siting areas based on a statewide siting assessment.

KEYWORDS: *Electric power plants, *Environmental impacts.

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STAFF REPORT

ENVIRONMENTAL IMPLICATIONS OF ELECTRIC UTILITY SUPPLY PLANS

1978-2000

Technical documentation for Staff Report, Assessment of Electric Utility Supply Plans
1978-2000

PREPARED BY

CALIFORNIA ENERGY COMMISSION
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California Energy Commission

MAY 1980

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Environmental Implications of Electricity Supply Plans

Table of Contents

Page

I. INTRODUCTION 1

II. SUMMARY AND CONCLUSIONS 7

III. AIR QUALITY 10

Projected Emissions from Power Plants 15

Air Quality Regulations 25

Air Basin Implications 29

North Coast Air Basin 30

Lake County Air Basin 32

Sacramento Valley Air Basin 32

Bay Area Air Basin 35

San Joaquin Valley Air Basin 37

North Central Coast Air Basin 39

South Central Coast Air Basin 41

South Coast Air Basin 43

Southeast Desert Air Basin 46

San Diego Air Basin 49

Northeast Plateau Air Basin 50

Out-of-State 50

Page

IV. WATER RESOURCES 55
Water Supply 55
Projected Water Requirements 57
Significance for State-wide Water Supply and Demand . . . 62
The Political and Regulatory Climate 65
The Options 66
Regional Implications 67
Water Quality 69
V. LAND USE 73
Generating Facility Land Requirements 73
Land Use for the Utilities' Plans 75
Regional Issues 76
Coastal vs. Inland Siting 76
Urban vs. Rural Siting 77
In-State vs. Out-of-State Siting 77
Geothermal Development 79
Federal Wilderness Area Designations 80
Transmission Line Routes 80
VI. NUCLEAR WASTES 81
Low Level Waste 82
High Level Waste 84
Decommissioning Waste 88
VII. COAL PLANT ASH AND SLUDGE 90
Characterization of Waste Products 90
Projected Waste Production 91
Disposal Considerations 95
Remaining Problems and Issues 97

List of Figures

Page

Figure 1 Proposed Electric Generation Facilities 1980-1991 4

Figure 2 Potential Siting Areas for Scenario 1A 5

Figure 3 Potential Siting Areas for Scenario 1B 6

Figure 4 Air Pollutant Emissions from Power Plants State Wide 12

Figure 5 Air Basins - California Air Resources Board Air Basins 14

Figure 6 Air Pollutant Emissions from Power Plants - North Coast Air Basin 31

Figure 7 Hydrogen Sulfide Emissions from Geothermal Power Plants - North Coast 33

Figure 8 Hydrogen Sulfide Emissions from Geothermal Power Plants - Lake County 34

Figure 9 Air Pollutant Emissions from Power Plants - Sacramento Valley Air Basin 36

Figure 10 Air Pollutant Emissions from Power Plants - San Francisco Bay Area Air Basin 38

Figure 11 Air Pollutant Emissions from Power Plants - San Joaquin Valley Air Basin 40

Figure 12 Air Pollutant Emissions from Power Plants - North Central Coast Air Basin 42

Figure 13 Air Pollutant Emissions from Power Plants - South Central Coast Air Basin 44

Figure 14 Air Pollutant Emissions by Power Plants - South Coast Air Basin 45

Page

Figure 15 Air Pollutant Emissions from Power Plants - Southeast Desert Air Basin 47

Figure 16 Hydrogen Sulfide Emissions from Geothermal Power Plants - Southeast Desert 48

Figure 17 Air Pollutant Emissions from Power Plants - San Diego Air Basin 51

Figure 18 Air Pollutant Emissions from Power Plants - Northeast Plateau Air Basin 52

Figure 19 Air Pollutant Emissions from Out of State Generation Serving California 54

Figure 20 Cooling Tower Water Consumption for Power Plants by Hydrologic Study Area 59

Figure 21 Hydrologic Basins of California 60

Figure 22 Statewide Water Requirements and Supplies 63

Figure 23 Quantities of Low Level Radioactive Waste Generated per Year 83

Figure 24 Quantities of High-Level Radioactive Waste Generated per Year 86

Figure 25 Projected Coal Plant Solid Waste Production 94

List of Tables

Page

Table 1 Summary of California Air Emissions by Generation type in 1976; 2000 (Scenario 1A); and 2000 (Scenario 1B) 17

Table 2 Power Plant Emissions by Air Basin 18-21

Table 3 Major Air Pollution Regulations Applicable to Power Plant Planning, Siting, and Operation . . . . . 26&26A

Table 4 Water-Related Characteristics of Generating Facilities Planned by California Utilities 56

Table 5 Types of Cooling Employed by Electric Generating Facilities 58

Table 6 Land Requirements for Different Generation Types 74

Table 7 Estimated Dates When On-Site Spent Fuel Storage of Current Nuclear Plants will Approach Capacity 87

Table 8 Trace Elements in Ash from Sage Point Coal 92

I. INTRODUCTION

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Electricity supply planning is increasingly affected by environmental concerns. The environmental effects of constructing and operating new generating facilities are receiving equal (or greater) attention than more traditional factors, such as cost and reliability, during the course of making capacity expansion decisions.

Often, however, attempts to accommodate environmental conflicts occur relatively late in the planning process, after fundamental commitments based primarily on other considerations have been made. Also, a single environmental issue may sometimes dominate supply decisions to the extent of obscuring the overall environmental and other merits of a particular course of action. Assessing the major environmental implications of implementing a certain supply strategy can help insure against unforeseen confrontations over environmental issues in later stages of the plan's development. Another objective of such assessment is to determine the future environmental effects of a total generation system, effects not otherwise examined during case-by-case evaluations of individual project proposals. The relative environmental features are important selection criteria where major choices between different electricity supply strategies remain.

The State Legislature recognized the need for environmental assessment at the resource-planning level, and directed the California Energy Commission (CEC) to review and evaluate the implications of the electric utilities' forecasts of loads and resources on critical environmental and other resources of the state.[1] This report presents the results of the staff's environmental assessment of the current electricity supply plans of the California utilities. The subject areas discussed represent the major categories of potential impacts from the

---

1. California Public Resources Code Section 25304

construction and operation of electric generation facilities, including air quality, water resources, land use, and solid waste disposal.

This assessment deals with the utilities' combined, long-term resource plans which were submitted to CEC in March 1978, and any revisions announced before July 1979. These plans involve a net expansion of 21,600 MW by 1991 of the utilities' generation systems, which presently include about 40,000 MW of installed capacity. The planned capacity additions, largely coal-fired, nuclear, and combined cycle projects, are intended to keep pace with the utility-projected growth rate of 3.5 percent per year in statewide electricity sales.

The utilities' supply plans are less definite after 1991; in some cases, only the amounts of "generic" new capacity expected to be needed are specified. Therefore, to facilitate an assessment through the year 2000, the utility plans were extended through that year based on two different sets of assumptions with respect to possible utility strategies. This resulted in Scenario IA which relies on coal-fired plants for most new capacity requirements, and Scenario 1B, where nuclear plants become the predominant choice of plant type. Both scenarios call for the construction of about 25,000 MW of new capacity between 1991 and 2000, while allowing for the retirement of 5000 MW of older, oil-fired generating facilities.

A more detailed description of the utilities' resource plans and the Scenario IA and IB extensions are contained in a separate CEC staff report.[2] Maps from this report show the locations of utility-proposed generation facilities and potential siting areas for the additional facilities needed for Scenarios IA and IB (Figs. 1, 2, and 3). The report also includes a general discussion of the methods used to designate potential siting areas based on a statewide siting assessment reported on in another staff document.[3]

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[2] Assessment of Electric Utility Supply Plans 1978-2000, (draft). November 1979. Final report expected in March 1980.

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[3] Constraints and Opportunities for Power Plant Siting: Technical Issues, November 1979.

Figure 1

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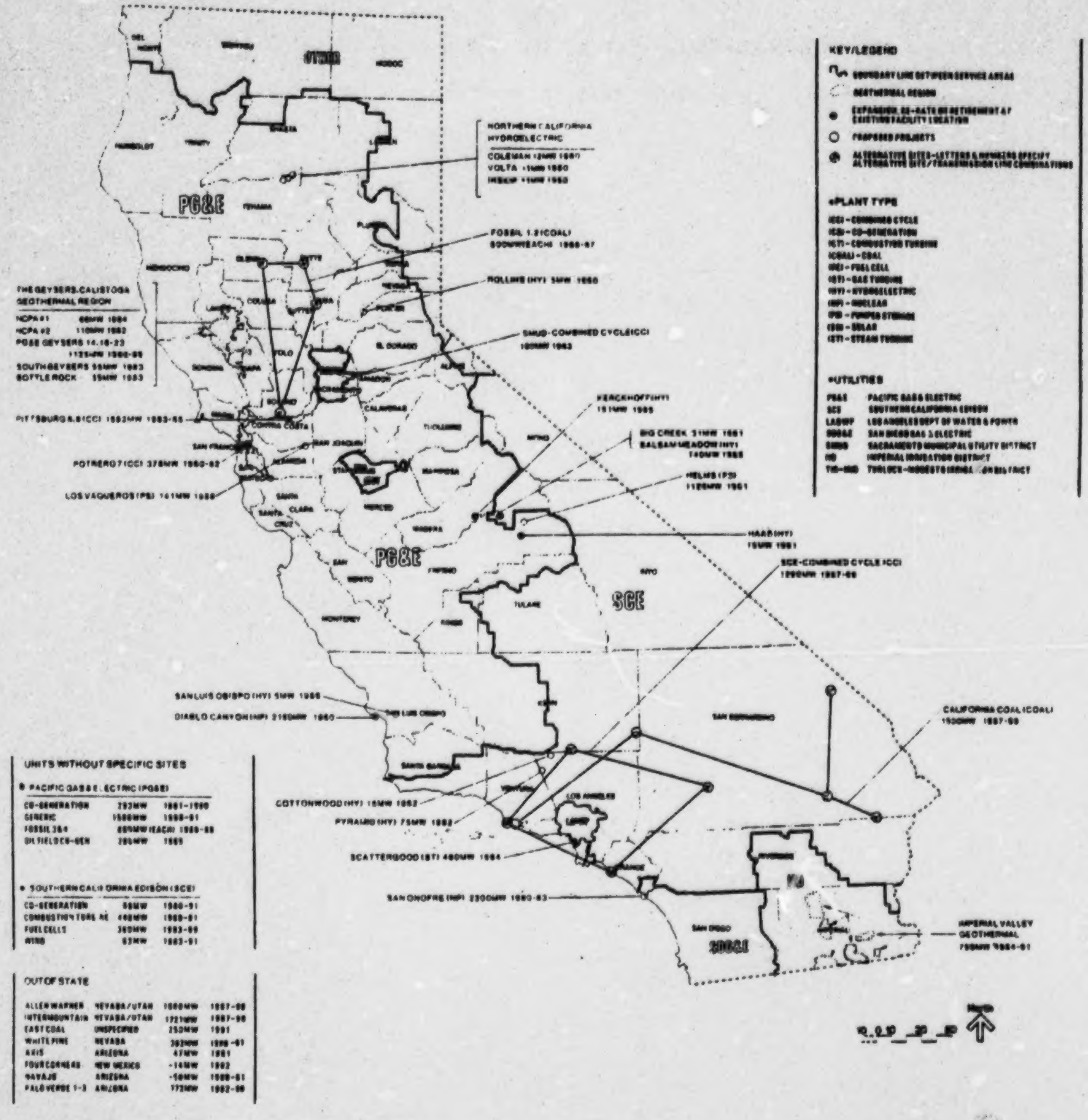

DEL NORTE
SISKIYOU
OTHER
MODOC
SHASTA
LASSEN
HUMBOLDT
TRINITY
TEHAMA
PG&E
NORTHERN CALIFORNIA HYDROELECTRIC
COLEMAN (2MW 1981)
VOLTA (1MW 1980
INSKIP (1MW 1982
FOSSIL 1,2 (COAL) 800MW (EACH) 1986-87
ROLLINS (HY) 5MW 1980
SMUD-COMBINED CYCLE (CC) 100MW 1983
MENDOCINO
COLUSA
EL DORADO
THE GEYSERS-CALISTOGA GEOTHERMAL REGION
NCPA #1 65MW 1984
NCPA #2 110MW 1983
PG&E GEYSERS 14,16-23 1135MW 1980-89
SOUTH GEYSERS 55MW 1983
BOTTLE ROCK 55MW 1983
SONOMA
YOLO
CALAVERAS
TUOLUMNE
KERCKHOFF (HY) 151MW 1985
BIG CREEK 31MW 1981
BALSAM MEADOW (HY) 140MW 1985
PITTSBURG 8,9 (CC) 1552MW 1983-85
CONTRA COSTA
SAN FRANCISCO
SAN JOAQUIN
POTRERO 7 (CC) 378MW 1980-82
ALAMEDA
MARIPOSA
MONO
HELMS (PS) 1125MW 1981
LOS VAQUEROS (PS) 161MW 1988
SANTA CLARA
SANTA CRUZ
MERCED
MADERA
HAAS (HY) 15MW 1981
SCE-COMBINED CYCLE (CC) 1280MW 1987-88
SAN BENITO
FRESNO
INYO
MONTEREY
TULARE
KINGS
SCE
SAN LUIS OBISPO (HY) 5MW 1986
DIABLO CANYON (NP) 2190MW 1980
SAN LUIS OBISPO
KERN
SAN BERNARDINO
CALIFORNIA COAL (COAL) 1500MW 1987-89
SANTA BARBARA
VENTURA
LOS ANGELES
LADWP
COTTONWOOD (HY) 15MW 1982
PYRAMID (HY) 75MW 1982
SCATTERGOOD (ST) 460MW 1984
ORANGE
RIVERSIDE
IID
SAN ONOFRE (NP) 2300MW 1980-83
SAN DIEGO
SDG&E
IMPERIAL VALLEY GEOTHERMAL 750MW 1984-91
KEY/LEGEND
BOUNDARY LINE BETWEEN SERVICE AREAS
GEOTHERMAL REGION
EXPANSION, RE-RATE OR RETIREMENT AT EXISTING FACILITY LOCATION
PROPOSED PROJECTS
ALTERNATIVE SITES-LETTERS & NUMBERS SPECIFY ALTERNATIVE SITE/TRANSMISSION LINE COMBINATIONS
*PLANT TYPE
(CC) - COMBINED CYCLE
(CG) - CO-GENERATION
(CT) - COMBUSTION TURBINE
(COAL) - COAL
(FC) - FUEL CELL
(GT) - GAS TURBINE
(HY) - HYDROELECTRIC
(NP) - NUCLEAR
(PS) - PUMPED STORAGE
(SO) - SOLAR
(ST) - STEAM TURBINE
*UTILITIES
PG&E PACIFIC GAS & ELECTRIC
SCE SOUTHERN CALIFORNIA EDISON
LADWP LOS ANGELES DEPT OF WATER & POWER
SDG&E SAN DIEGO GAS & ELECTRIC
SMUD SACRAMENTO MUNICIPAL UTILITY DISTRICT
IID IMPERIAL IRRIGATION DISTRICT
TID-MID TURLOCK-MODESTO IRRIGATION DISTRICT
North
10 0 10 20 30

UNITS WITHOUT SPECIFIC SITES

● PACIFIC GAS & ELECTRIC (PG&E)

CO-GENERATION	293MW	1981-1990
GENERIC	1500MW	1988-91
FOSSIL 3&4	800MW (EACH)	1988-90
OILFIELD CO-GEN	285MW	1985

● SOUTHERN CALIFORNIA EDISON (SCE)

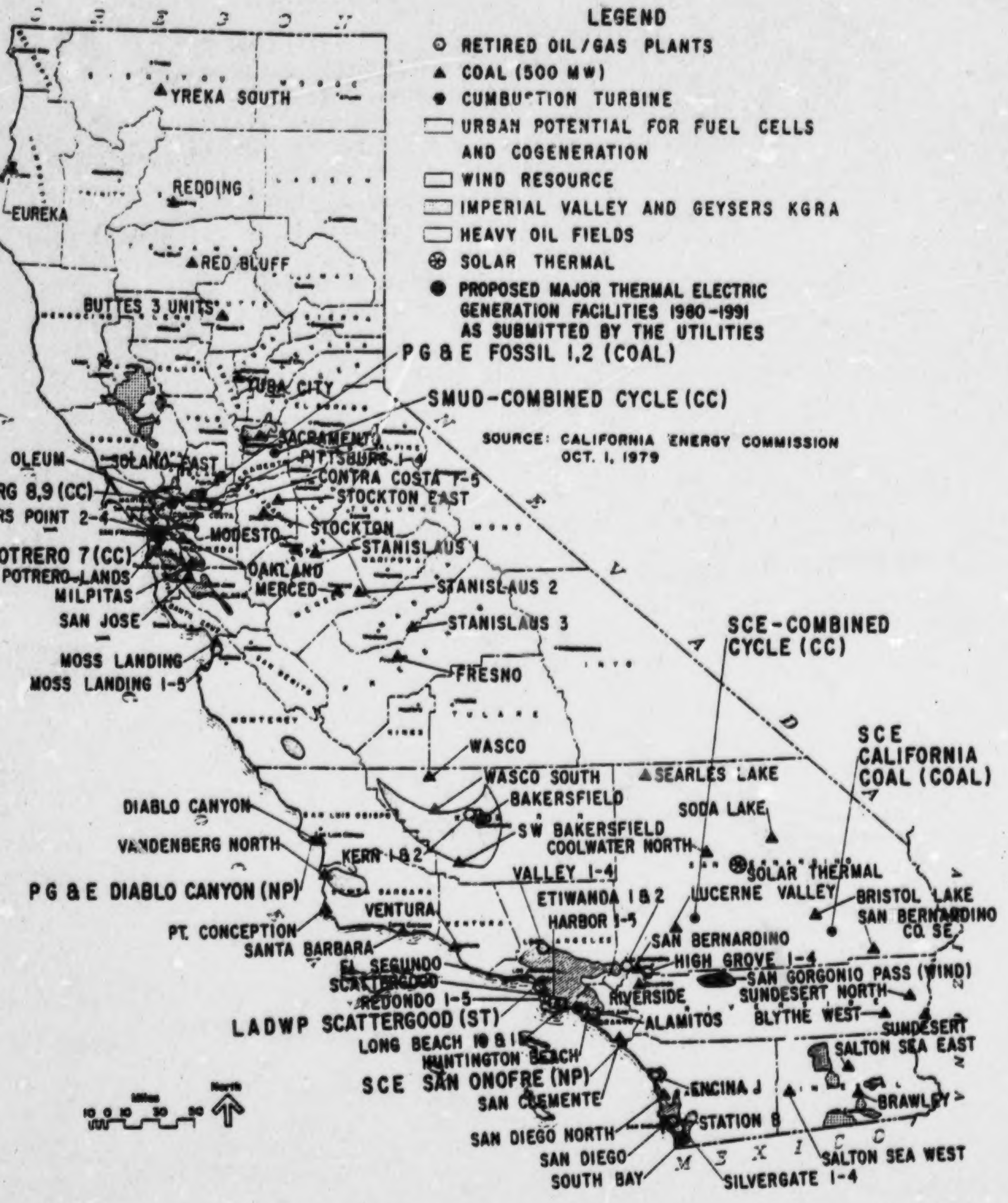
CO-GENERATION	50MW	1980-91
COMBUSTION TURBINE	440MW	1980-81
FUEL CELLS	360MW	1983-90
WIND	63MW	1983-91

OUT OF STATE

ALLEN WARNER	NEVADA/UTAH	1000MW	1987-90
INTERMOUNTAIN	NEVADA/UTAH	1721MW	1987-90
EAST COAL	UNSPECIFIED	250MW	1991
WHITE PINE	NEVADA	383MW	1990-91
AXIS	ARIZONA	47MW	1981
FOUR CORNERS	NEW MEXICO	-14MW	1982
NAVAJO	ARIZONA	-50MW	1980-81
PALO VERDE 1-3	ARIZONA	772MW	1982-86

CALIFORNIA ELECTRIC UTILITIES
PROPOSED ELECTRIC GENERATION FACILITIES 1980-1991
Compiled by the California Energy Commission JULY 1, 1979

Figure 2

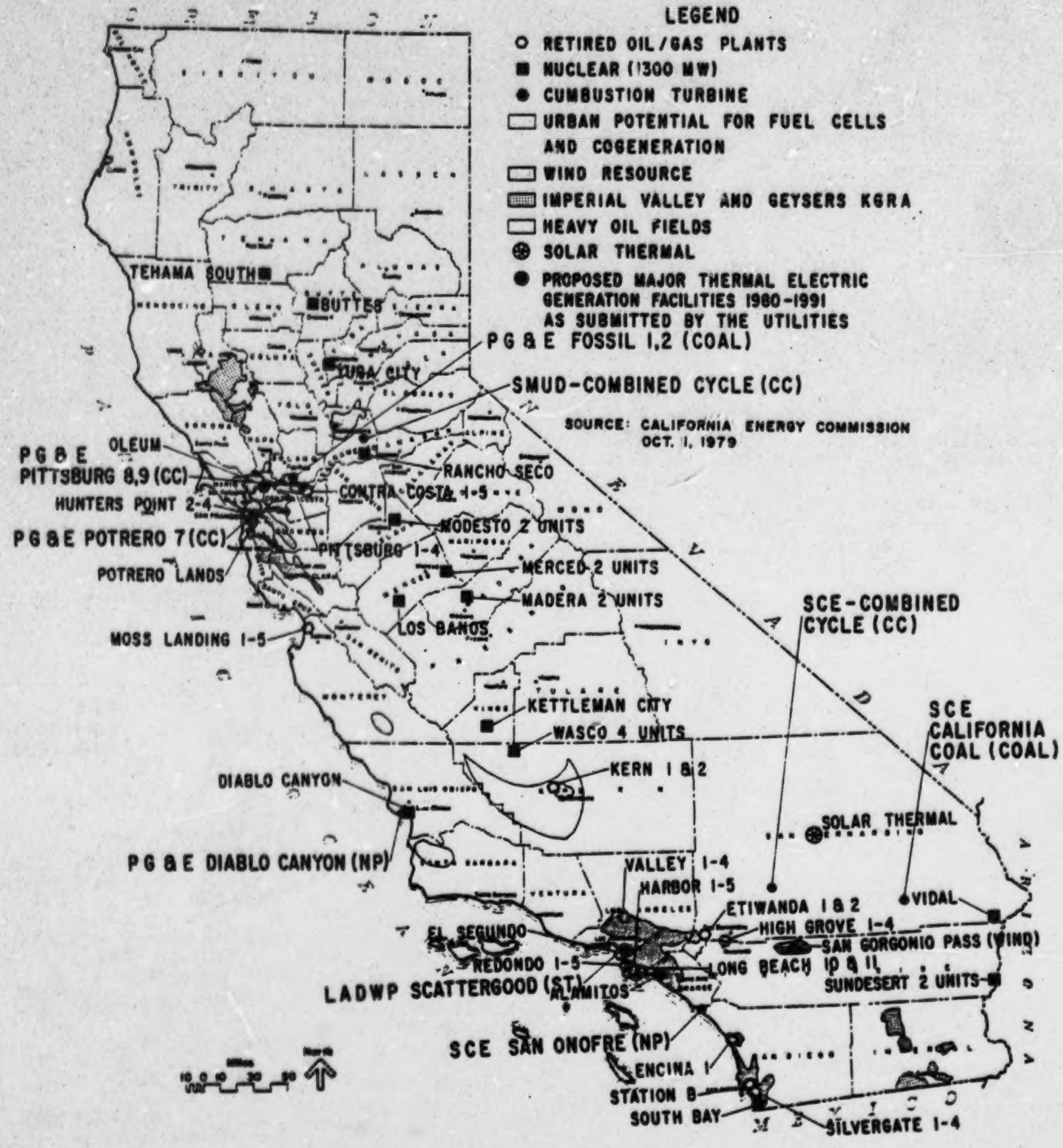


LEGEND
○ RETIRED OIL/GAS PLANTS
▲ COAL (500 MW)
● CUMBUSTION TURBINE
▭ URBAN POTENTIAL FOR FUEL CELLS AND COGENERATION
▭ WIND RESOURCE
▨ IMPERIAL VALLEY AND GEYSERS KGRA
▭ HEAVY OIL FIELDS
⊛ SOLAR THERMAL
● PROPOSED MAJOR THERMAL ELECTRIC GENERATION FACILITIES 1980-1991 AS SUBMITTED BY THE UTILITIES
OREGON
NEVADA
MEXICO
YREKA SOUTH
EUREKA
REDDING
RED BLUFF
BUTTES 3 UNITS
PG & E FOSSIL 1,2 (COAL)
YUBA CITY
SMUD-COMBINED CYCLE (CC)
SACRAMENTO
PITTSBURG 1-4
CONTRA COSTA 1-5
STOCKTON EAST
OLEUM
SOLANO EAST
PG & E PITTSBURG 8,9 (CC)
HUNTERS POINT 2-4
MODESTO
STOCKTON
STANISLAUS 1
PG & E POTRERO 7 (CC)
POTRERO LANDS
MILPITAS
OAKLAND
MERCED
STANISLAUS 2
SAN JOSE
STANISLAUS 3
MOSS LANDING
MOSS LANDING 1-5
FRESNO
SCE-COMBINED CYCLE (CC)
WASCO
WASCO SOUTH
SEARLES LAKE
SCE CALIFORNIA COAL (COAL)
BAKERSFIELD
DIABLO CANYON
SW BAKERSFIELD
SODA LAKE
COOLWATER NORTH
VANDENBERG NORTH
KERN 1 & 2
SOLAR THERMAL
VALLEY 1-4
PG & E DIABLO CANYON (NP)
ETIWANDA 1 & 2
LUCERNE VALLEY
BRISTOL LAKE
HARBOR 1-5
SAN BERNARDINO CO. SE
VENTURA
SAN BERNARDINO
PT. CONCEPTION
SANTA BARBARA
HIGH GROVE 1-4
EL SEGUNDO
SAN GORGONIO PASS (WIND)
SCATTERGOOD
SUNDESERT NORTH
REDONDO 1-5
RIVERSIDE
BLYTHE WEST
LADWP SCATTERGOOD (ST)
ALAMITOS
SUNDESERT
LONG BEACH 10 & 11
SALTON SEA EAST
HUNTINGTON BEACH
SCE SAN ONOFRE (NP)
ENCINA J
SAN CLEMENTE
BRAWLEY
STATION B
SAN DIEGO NORTH
SAN DIEGO
SALTON SEA WEST
SOUTH BAY
SILVERGATE 1-4
Miles
10 0 10 30 50
North

SOURCE: CALIFORNIA ENERGY COMMISSION
OCT. 1, 1979

POTENTIAL SITING AREAS FOR SCENARIO IA

Figure 3


LEGEND
○ RETIRED OIL/GAS PLANTS
■ NUCLEAR (1300 MW)
● CUMBUSTION TURBINE
▭ URBAN POTENTIAL FOR FUEL CELLS AND COGENERATION
▭ WIND RESOURCE
▨ IMPERIAL VALLEY AND GEYSERS KGRA
▭ HEAVY OIL FIELDS
⊛ SOLAR THERMAL
● PROPOSED MAJOR THERMAL ELECTRIC GENERATION FACILITIES 1980-1991 AS SUBMITTED BY THE UTILITIES
TEHAMA
SOUTH
BUTTES
YUBA CITY
P G & E FOSSIL 1,2 (COAL)
SMUD-COMBINED CYCLE (CC)
OLEUM
P G & E PITTSBURG 8,9 (CC)
HUNTERS POINT 2-4
P G & E POTRERO 7 (CC)
POTRERO LANDS
RANCHO SECO
CONTRA COSTA 1-5
MODESTO 2 UNITS
PITTSBURG 1-4
MERCED 2 UNITS
MADERA 2 UNITS
LOS BANOS
MOSS LANDING 1-5
NEVADA
SCE-COMBINED CYCLE (CC)
KETTLEMAN CITY
WASCO 4 UNITS
KERN 1 & 2
DIABLO CANYON
P G & E DIABLO CANYON (NP)
SCE CALIFORNIA COAL (COAL)
SOLAR THERMAL
VALLEY 1-4
HARBOR 1-5
ETIWANDA 1 & 2
VIDAL
HIGH GROVE 1-4
SAN GORGONIO PASS (WIND)
EL SEGUNDO
REDONDO 1-5
LONG BEACH 10 & 11
SUNDESERT 2 UNITS
LADWP SCATTERGOOD (ST)
ALAMITOS
SCE SAN ONOFRE (NP)
ENCINA 1
STATION B
SOUTH BAY
SILVERGATE 1-4
ARIZONA
MEXICO
Miles
10 0 10 30 50
North

SOURCE: CALIFORNIA ENERGY COMMISSION OCT. 1, 1979

POTENTIAL SITING AREAS FOR SCENARIO IB

II. SUMMARY AND CONCLUSIONS

California utilities plan to meet their projected demands for electricity during the next 20 years by continuing to rely heavily on existing generation sources along with adding many new facilities. Environmental interest in these plans usually focuses on the effects of building and operating the planned new facilities. However, to get the complete picture of the environmental implications of prospective electric generation, the effects of the total system, including the contributions of existing facilities, must be considered. Of particular importance for air quality is the extent to which generation from older, inefficient power plants is displaced as new, cleaner plants go into operation.

The utilities' most recently announced plans propose major expansion of their fossil fuel-fired generating capacity during the next 12 years, including the state's first coal-burning plants. During this period, a significant increase in nuclear generation from plants already in construction or in advanced planning stages is also planned. In the longer term (1991-2000), regulatory and other uncertainties face both nuclear and coal development, and limit formal commitment to further reliance on either option at this time. The implications of future utility emphasis on coal or on nuclear energy need to be explored.

Whichever supply strategy is selected, the utilities foresee a more than doubling of their installed generating capacity and electricity generated by the year 2000. Assessment of the utilities' generation plans, incorporating the scheduled capacity additions (with long-term emphasis on either coal or nuclear) into total system operations, reveals the following major environmental implications associated with the plans' implementation:

- Power plant emissions in the state's urban air basins would generally increase slightly by 1991, due mainly to federal restriction of natural gas use. By the year 2000, power plant emissions in urban basins would, for the most part, diminish to less than present-day levels as generation from older, more polluting plants is reduced.

- In certain air basins which now have little or no emissions from electric generation, fossil-fuel power plants would become major new contributors to total basin emissions. Limited availability of emissions offsets (trade-offs) from existing sources, along with other air quality regulations, pose serious obstacles to the construction of these facilities.

- The Coal Scenario (IA) and the Nuclear Scenario (IB) differ little with respect to air emissions through 1991, but by the year 2000, the additional coal plants in IA will result in significant differences in emissions between the two scenarios in some air basins. Certain air basins would actually experience higher emission levels in the nuclear case due to its greater reliance on oil-fired generation to meet total energy requirements.

- Power plant emissions in many air basins during the 1977 drought year were higher than those projected for any future year (without a drought).

- Effective control of hydrogen sulfide (H_2S) emissions from geothermal power plants is a critical requirement for realizing the planned levels of use of this technology. If expected control levels are reached, future H_2S emissions in the North Coast Air Basin will be only about one-fifth of current levels. It would also mean that total power plant emissions throughout The Geysers KGRA would be within the ARB's guidelines for achieving the ambient H_2S standard. However, the slow development of H_2S control technologies, and specific steam supply and siting problems make the future of some projects uncertain.

- Planned nuclear power plant operations face a dilemma due to impending exhaustion of temporary storage facilities for high-level radioactive wastes. In the absence of provisions for permanent waste disposal, the continued availability of out-of-state disposal sites for low-level radioactive wastes is also a problem of increasing importance.

- Inland water supply requirements for power plant cooling tower make-up would increase from the present 40,000 acre-feet per year to between 360,000 and 450,000 acre-feet per year by the year 2000. This appears to present less of an environmental conflict than the conflict over allocating a relatively small portion (about 1 percent) of the state's water supply among competing uses.

- The use of ocean water for cooling power plants currently under construction, with attendant effects on the marine environment, will increase significantly.

- It appears to be possible to dispose of coal plant ash and sludge within applicable environmental regulations. However, it is necessary to continue to investigate alternative disposal sites, improved disposal practices, and beneficial reuse schemes to further reduce the potential adverse environmental effects of disposing of this material.

- Land requirements for generation facilities and transmission line rights-of-way could become a significant part of expanding urban development in the state.

III. AIR QUALITY

Air pollutant emissions from power plants burning fossil fuels are of considerable environmental concern with respect to both present and future electric energy supply. In California, power plants presently contribute the following portions of the total emissions of major air pollutants: about 30 percent of sulfur oxides (SO_x), 10 percent of nitrogen oxides (NO_x), and less than 1 percent of total suspended particulate matter (TSP) and hydrocarbons (HC).

In certain air basins, significant air quality problems exist, and ambient air quality standards for some or all of the above pollutants--or secondary pollutants formed from them--are exceeded. In some of these basins, power plants contribute a larger fraction of the total emissions than is reflected by the statewide percentages. Therefore, prospective changes in the electric generation sector are an important consideration in local air quality regulatory and planning programs.

From a statewide perspective, the utilities' resource plans have a number of features significant to air quality analysis:

- The utilities project roughly a doubling of electricity generation in the next 20 years, but by adding facilities with greatly improved emissions characteristics.

- A major change is planned in the mix of fossil-fueled generation technologies from almost entirely oil- and gas-fueled steam turbines to major contributions from combined cycle and coal-fired plants.

- Development of geothermal resources, both vapor- and liquid-dominated, will be expanded substantially.

- Nuclear power plants will generate a more significant portion of the state's electricity, even if no new nuclear projects (beyond those in progress) are undertaken.

The net implications of these changes on the state's air quality depend on the geographic level of detail being examined. At the statewide level (Fig. 4), the following general trends result:

- There will be lower, but still significant, amounts of NO_x emissions due to replacement of old, dirtier power plants with new cleaner ones, along with an increasing contribution from nuclear power.

- Emissions of SO_x and particulates will increase slightly by 1991, then decrease toward the year 2000. The increase to 1991 can be attributed to the restricted use of natural gas in power plants under the Power Plant and Industrial Fuel Use Act (PIFUA). The decrease by 2000 will result from the projected retirements (or reductions in operating-level) of older oil-burning plants.

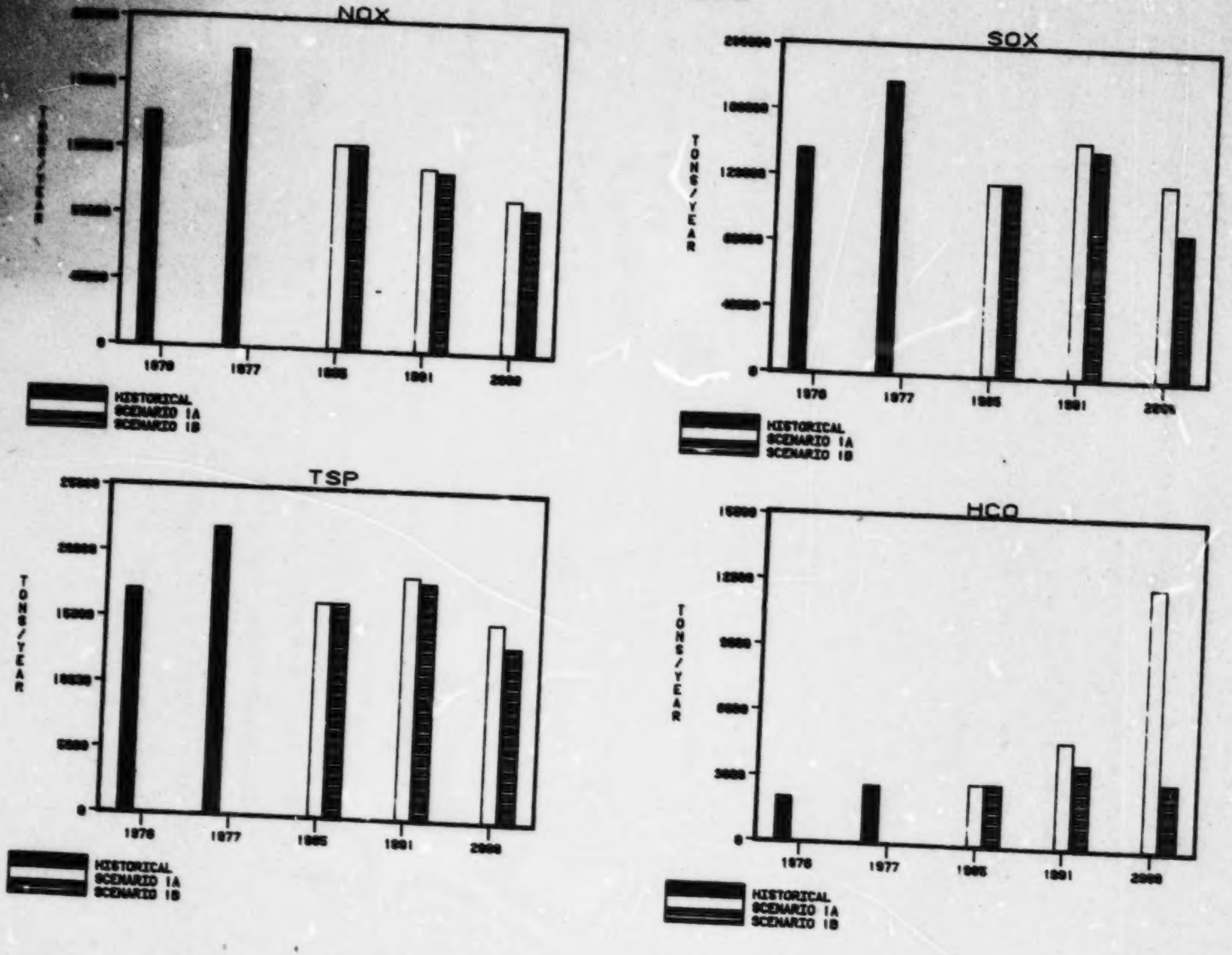
- Hydrocarbon emissions from power plants, although increasing, will remain a small portion of the total hydrocarbon emissions.

- There will be less hydrogen sulfide (H_2S) released--compared to existing levels--if expected control technologies are achieved on both new and existing geothermal operations.

- Statewide emissions of all pollutants, except H_2S, would be slightly lower by the year 2000 in the nuclear case (Scenario IB) than the coal case (Scenario IA).

Figure 4

AIR POLLUTANT EMISSIONS FROM POWER PLANTS
STATE WIDE



ss

These statewide trends do not adequately reflect, the individual regional consequences which, in actuality, are most important. The types and locations of planned new generating facilities and the future operating schedules for existing facilities are primary factors in determining the distribution of air pollutant emissions in the state. Therefore, implications of the utility supply plans were assessed for each of the state's 14 air basins (Fig. 5). The following are some of the more important observations resulting from this assessment:

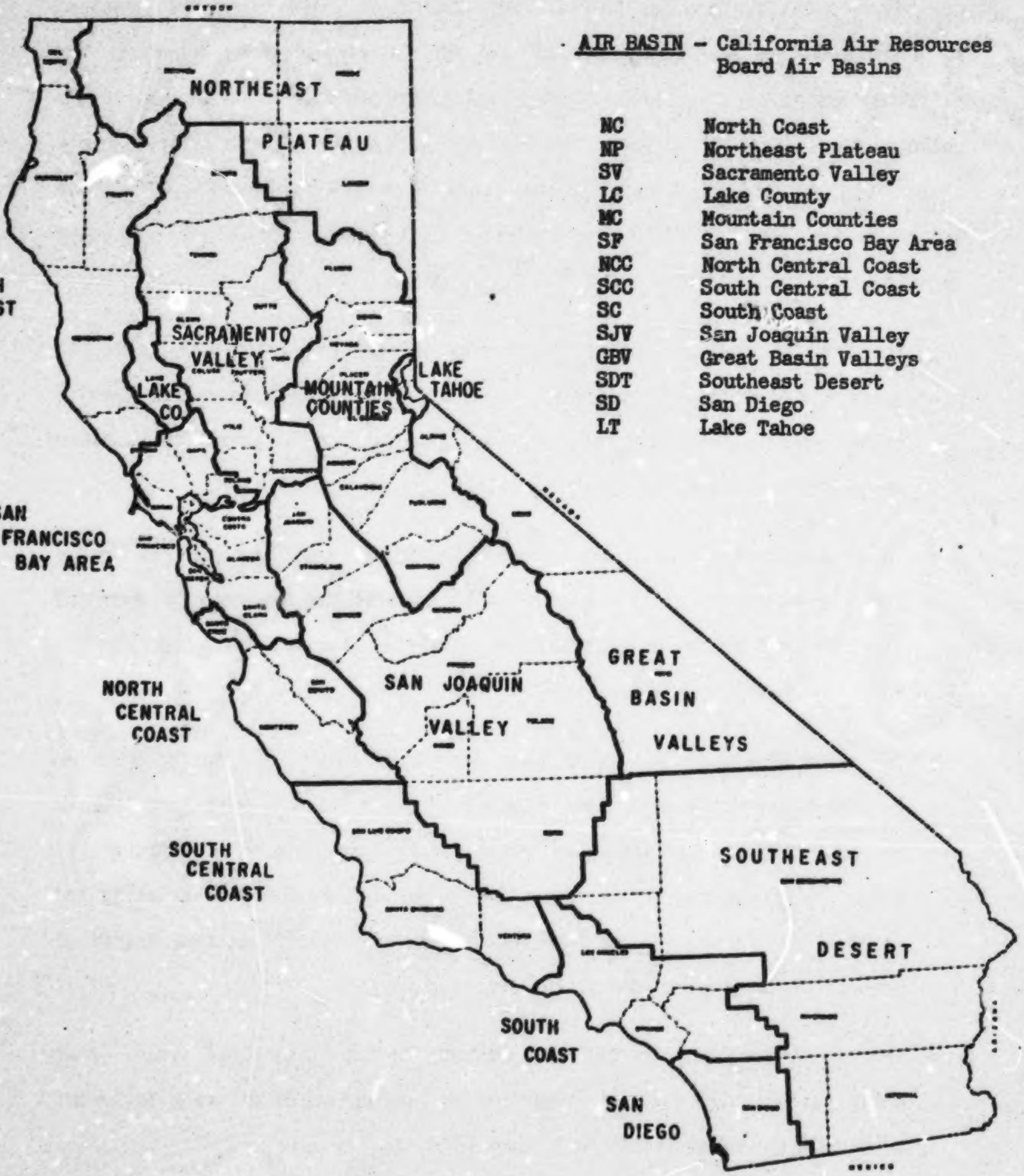
- The state's urban air basins (San Francisco Bay Area, South Coast, and San Diego Air Basins) will continue to be affected by emissions from fossil-fueled power plants, but to a decreasing extent by the year 2000 as older power plants are phased out of operation.

- Rural air basins (including the Southeast Desert, San Joaquin Valley and Sacramento Valley Air Basins) will be affected the most by expanded electric generation, a contributing factor to the expected decreases in emissions in the urban basins.

- The North Coast, Lake County, and Southeast Desert Air Basins will be affected by geothermal development. Levels of H_2S emissions should be reduced in The Geysers Known Geothermal Resource Area (KGRA) through the use of emission-control equipment being implemented for both existing and planned facilities. Although none is presently specified, some degree of control may also be needed in the Imperial Valley.

- Several of the more "remote" air basins, including the Lake Tahoe, Great Basin Valleys, and Mountain Counties Air Basins are not likely to become candidate areas for fossil fuel power plants.

FIGURE 5


NORTHEAST
PLATEAU
NORTH COAST
SACRAMENTO VALLEY
LAKE CO
MOUNTAIN COUNTIES
LAKE TAHOE
SAN FRANCISCO BAY AREA
NORTH CENTRAL COAST
SAN JOAQUIN VALLEY
GREAT BASIN VALLEYS
SOUTH CENTRAL COAST
SOUTHEAST
DESERT
SOUTH COAST
SAN DIEGO

AIR BASIN - California Air Resources Board Air Basins

NC	North Coast
NP	Northeast Plateau
SV	Sacramento Valley
LC	Lake County
MC	Mountain Counties
SF	San Francisco Bay Area
NCC	North Central Coast
SCC	South Central Coast
SC	South Coast
SJV	San Joaquin Valley
GBV	Great Basin Valleys
SDT	Southeast Desert
SD	San Diego
LT	Lake Tahoe

Projected Emissions from Power Plants

The foundation of this air quality evaluation is an inventory of oxides of nitrogen (NO_x), oxides of sulfur (SO_x), total suspended particulate matter (TSP), hydrocarbons (HC), and in appropriate air basins, hydrogen sulfide (H_2S). These pollutants were chosen because they pose potential constraints to power plant siting if utilities cannot comply with applicable regulations. These encompass all pollutants which have federal ambient air quality standards except carbon monoxide (CO). Since nearly all emissions of CO are from mobile sources and not power plants, it is not included. Generally, power plants will not contribute significantly to any violations which may exist of the ambient standards for CO.

The emissions projections used in this study do not account for any emission reductions or trade-offs that may be required under New Source Review (NSR) regulations. The power plant emissions presented here are the amounts of each pollutant expected at the stack under normal operation. Trading-off emissions from new power plants would mean a compensatory reduction of emissions from other power plants or polluters, usually within the same air basin, and generally, the total basin emissions for that pollutant would not increase.

Power plant cooling towers are potentially significant source of emissions which was not quantified in this analysis. Cooling towers emit droplets containing particulate matter, salts, and other trace contaminants which could be detrimental to agriculture or public health. Although these emissions are not currently regulated and their impacts are not fully understood, it is evident that the quality of make-up water used in cooling towers greatly affects the quantity and quality of subsequent emissions. A study cosponsored by the CEC and the State Air Resources Board, is investigating the nature and extent of aerosol emissions from cooling towers.

Power plants of the 1990s will be cleaner than existing plants, per unit of electricity generated. This can be seen by comparing the system-wide pounds/megawatt hour columns of Table 1. The forecasted need to generate more electricity counteracts the trend toward cleaner plants and anticipated emission reductions, forcing the continued reliance on existing plants through this period. The heavy expansion of geothermal generation--an almost five-fold increase--is more than offset by the substantial improvement expected in emissions characteristics.

In Table 2, estimated power plant emissions for each of the state's air basins is summarized for the years 1985, 1991, and 2000, given the facilities and siting assumptions of the two alternative cases (Scenarios IA and IB). Data from 1976 and 1977 are included to compare the historical experience with the projected case. The 1977 data are higher than would be expected because 1977 was a drought year, and fossil-fuel power was relied on more heavily due to decreased hydroelectric capacity. The emissions projections were derived using the Commission staff's "Residuals Model."[4]

These projections are reasonable approximations of emissions likely to result from implementing the two variations of the utilities' plans. Nevertheless, the actual emissions resulting from implementation of the resource plans could vary from these estimates due to several factors, including the following:

- Drought. Drought substantially lowers energy production from hydroelectric facilities, and consequently, increases reliance on fossil fuel facilities. Emissions from the fossil-fuel plants will increase accordingly, as

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4. A detailed description of this model, The California Model For Computing Residuals And Water Consumption For Electric Power Plants, is contained in a draft report: Environmental Evaluation of Electricity Supply Options Using The California Energy Commission's Residuals Model, L. Joyce, CEC, 1980.

SUMMARY OF CALIFORNIA AIR EMISSIONS BY GENERATION TYPE IN 1976

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Generation Type	NO_x lbs/MWh	NO_x Tons	SO_x lbs/MWh	SO_x Tons	Particulates lbs/MWh	Particulates Tons	Hydro-Carbons lbs/MWh	Hydro-Carbons Tons	H_2S lbs/MWh	H_2S Tons
Oil/Gas-Fueled										
Steam Turbine	3.55	157,744	3.04	135,140	.38	16,871	.05	2,024		
Combustion Turbine	5.46	1,155	3.32	703	.94	198	.10	21		
Geothermal										
Vapor									4.16	7,513
TOTAL EMISSIONS		158,899		135,140		17,069		2,045		7,513

SCENARIO 1A

SUMMARY OF CALIFORNIA AIR EMISSIONS BY GENERATION TYPE IN 2000

Generation Type	NO_x lbs/MWh	NO_x Tons	SO_x lbs/MWh	SO_x Tons	Particulates lbs/MWh	Particulates Tons	Hydro-Carbons lbs/MWh	Hydro-Carbons Tons	H_2S lbs/MWh	H_2S Tons
Oil/Gas-Fueled										
Steam Turbine	3.30	58,023	2.88	50,483	.48	8,361	.06	1,085		
Combustion Turbine	3.43	5,469	2.19	3,497	.72	1,145	.09	149		
Combined Cycle	.91	2,859	.28	892	.06	174	.02	71		
Fuel Cell	.19	54	-	-	-	-	.01	3		
Cogeneration	2.01	10,428	1.56	8,116	.09	468	.04	200		
Coal-Fueled										
Steam Turbine	.35	28,458	.70	56,077	.06	5,022	.13	10,462		
Geothermal										
Liquid									.22	1,034
Vapor									.31	2,156
TOTAL EMISSIONS		105,291		119,065		15,170		11,970		3,190

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SCENARIO 1B

SUMMARY OF CALIFORNIA AIR EMISSIONS BY GENERATION TYPE IN 2000

Generation Type	NO_x lbs/MWh	NO_x Tons	SO_x lbs/MWh	SO_x Tons	Particulates lbs/MWh	Particulates Tons	Hydro-Carbons lbs/MWh	Hydro-Carbons Tons	H_2S lbs/MWh	H_2S Tons
Oil/Gas-Fueled										
Steam Turbine	3.40	76,168	3.14	70,353	.49	10,939	.06	1,385		
Combustion Turbine	3.43	5,463	2.19	3,497	.72	1,146	.09	149		
Combined Cycle	.83	3,542	.24	1,032	.05	210	.02	86		
Fuel Cell	.19	54	-	-	-	-	.01	3		
Cogeneration	2.01	10,428	1.56	8,116	.09	468	.04	200		
Coal-Fueled										
Steam Turbine	.35	3,481	.70	6,860	.06	615	.13	1,280		
Geothermal										
Liquid									.22	1,034
Vapor									.31	2,156
TOTAL EMISSIONS		99,136		89,858		13,378		3,103		3,190

TABLE 2

POWER PLANT EMISSIONS BY AIR BASIN[1]

TONS OF POLLUTANTS

AIR BASIN[2] AND POLLUTANTS	1976	1977	1985 1A	1985 1B	1991 1A	1991 1B	2000 1A	2000 1B
San Fracisco Bay Area								
NO_x	61,000	69,000	34,000	34,000	28,000	28,000	26,000	34,000
SO_x	25,000	29,000	24,000	24,000	29,000	29,000	19,000	22,000
TSP	3,600	4,000	2,400	2,400	3,300	3,300	3,000	3,800
HC	390	450	490	490	960	960	1,300	860
North Central Coast								
NO_x	12,000	18,000	10,000	10,000	12,000	12,000	2,400	4,200
SO_x	9,100	15,000	6,200	6,200	23,000	23,000	4,700	8,300
TSP	1,200	1,800	910	910	2,300	2,300	470	850
HC	140	210	110	110	290	290	230	110
Sacramento Valley								
NO_x	0	0	0	0	1,500	760	4,100	810
SO_x	0	0	0	0	3,000	1,500	8,200	1,600
TSP	0	0	0	0	270	130	730	140
HC	0	0	0	0	560	280	1,500	300
San Joaquin Valley								
NO_x	2,400	5,800	1,200	1,200	2,400	1,400	8,200	2,100
SO_x	1,700	5,300	420	420	2,800	810	13,000	1,200
TSP	150	450	2	2	210	32	1,300	210
HC	12	35	47	47	420	50	2,300	100

TABLE 2

POWER PLANT EMISSIONS BY AIR BASIN[1]

AIR BASIN[2] AND POLLUTANTS	TONS OF POLLUTANTS							
	1976	1977	1985		1991		2000	
			1A	1B	1A	1B	1A	1B
South Central Coast								
NO_x	23,000	26,000	24,000	24,000	24,000	24,000	12,000	13,000
SO_x	22,000	26,000	16,000	16,000	23,000	23,000	14,000	12,000
TSP	2,600	3,100	3,400	3,400	3,900	3,900	2,300	2,300
HC	310	360	400	400	460	460	1,100	270
South Coast								
NO_x	48,000	69,000	56,000	56,000	40,000	40,000	34,000	34,000
SO_x	62,000	83,000	47,000	47,000	36,000	36,000	32,000	29,000
TSP	7,800	10,000	7,600	7,600	6,000	6,000	4,900	4,900
HC	940	1,300	1,400	1,400	1,000	1,000	1,700	880
San Diego								
NO_x	8,700	10,000	9,600	9,600	9,700	9,700	5,400	5,300
SO_x	10,000	12,000	16,000	16,000	16,000	16,000	7,400	6,900
TSP	1,700	2,000	1,800	1,800	1,800	1,800	800	780
HC	220	270	270	270	280	280	460	120
Southeast Desert								
NO_x	2,900	3,700	4,800	4,800	6,600	5,700	11,000	5,000
SO_x	5,200	6,500	7,900	7,900	9,300	7,400	19,000	7,000
TSP	191	241	476	476	725	574	1,600	496
HC	25	31	110	110	821	480	2,800	470
H_2S	0	0	9	9	530	530	1,000	1,000

TABLE 2

POWER PLANT EMISSIONS BY AIR BASIN[1]

TONS OF POLLUTANTS

AIR BASIN[2] AND POLLUTANTS	1976	1977	1985		1991		2000	
			1A	1B	1A	1B	1A	1B
North Coast								
NO_x	880	1,200	630	630	790	790	640	300
SO_x	850	1,700	1	1	2,300	2,300	1,400	900
TSP	78	140	13	13	180	180	120	67
HC	5	9	1	1	10	10	190	4
H_2S	7,500	7,400	1,400	1,400	1,400	1,400	1,400	1,400
Northeast Plateau								
NO_x	0	0	0	0	0	0	500	0
SO_x	0	0	0	0	0	0	990	0
TSP	0	0	0	0	0	0	89	0
HC	0	0	0	0	0	0	190	0
Lake County								
H_2S	0	0	630	630	720	720	730	730
Statewide								
NO_x	160,000	200,000	140,000	140,000	130,000	120,000	110,000	99,000
SO_x	140,000	180,000	120,000	120,000	140,000	140,000	120,000	90,000
TSP	17,000	22,000	17,000	17,000	19,000	18,000	15,000	14,000
HC	2,000	2,700	2,800	2,800	4,800	3,800	12,000	3,100
H_2S	7,500	7,400	2,000	2,000	2,700	2,700	3,200	3,200

TABLE 2

POWER PLANT EMISSIONS BY AIR BASIN[1]
AIR BASIN[2] AND
POLLUTANTS

TONS OF POLLUTANTS

	1976	1977	1985 1A	1985 1B	1991 1A	1991 1B	2000 1A	2000 1B
Out-of-State								
NO_x	55,000	59,000	39,000	39,000	87,000	87,000	93,000	90,000
SO_x	52,000	57,000	45,000	45,000	56,000	56,000	60,000	58,000
TSP	9,400	10,000	10,000	10,000	12,000	12,000	13,000	12,000
HC	920	1,000	1,000	1,000	2,100	2,000	2,600	2,100

[1] As calculated by the "California Model for Computing Residuals and Water Consumption for Electric Power Plants" based on the utilities resource plans and staff scenarios 1A & 1B.

[2] The following projects have candiate sites in more than one air basin. They have been assigned to the indicated air basin for this analysis.

PG&E Fossil 1 & 2: San Francisco Bay
PG&E Fossil 3 & 4: Sacramento Valley
SCE California Coal: Southeast Desert
SCE Combined Cycle: Southeast Desert

evidenced by the 1977 levels. These increased emissions in-state would depend not only on the severity of the drought in California, but also on its extent throughout the Pacific Northwest, which provides a significant portion of the state's energy supply. However, hydroelectric power is projected to comprise a decreasing proporation of the state's electrical power supply in the future, and the relative impact of drought years will diminish. The possibility also exists that hydroelectric generation will be higher than the average-year assumption used in this study; this will result in somewhat lower emissions.

Power plant emission levels (except HC) will probably never again reach the levels of 1977; generally, power plant emissions are expected to decrease from the present level under normal system operation. A drought as severe as that in 1977 could, however, result in even higher emissions if natural gas or other clean fuels are not available for use.

o Plant Availability and Project Delays. The shutdown of nuclear plants or delays in other projected power plants would increase emissions from fossil-fueled facilities. Generally, when the operation of a new fossil-fueled plant is delayed, the needed energy would be supplied by older, more-polluting facilities. The extent to which emissions are increased depends on the supply mix of the service area affected, where the make-up energy comes from, and how it is generated. For instance, during the recent shutdown of Sacramento Municipal Utility District's Rancho Seco nuclear power plant, Pacific Gas and Electric Company was faced with the prospect of replacing almost 900 MW of capacity if the shutdown continued through the summer. Three sources were considered: Northwest hydroelectric power, southern California utilities, and PG&E's own generation system. The last two options would increase the use of fossil-fueled power plants. If PG&E made up all the energy within its own system, emissions from the company's fossil-fueled plants (located in the San Francisco Bay, North Central Coast, and South Central Coast Air Basins) would increase up to 20 percent annually without the operation of Rancho Seco.[5]

- o Control Technology Effectiveness. Performance of air pollution control equipment is a major variable affecting future emission levels. Advanced or innovative control technologies on new energy facilities could cause reliability problems or affect net facility efficiency, as well as be ineffective as an abatement meaure. If this occurs, higher than expected emissions could result from the new facilities (if they are allowed to operate) or from older facilities operating at higher capacity to make up the energy otherwise provided by the new plant.

  In particular, this analysis assumes advanced controls for NOx emissions from in-state coal plants by 1991. Selective catalytic reduction with ammonia injection is expected to abate 90 percent of the NOx emissions from such plants. Other control technologies anticipated for California coal plants are lime/limestone flue-gas-desulfurization equipment, to remove 95 percent of the sulfur in the stack gas, and fabric filter baghouses, capable of particulate control in excess of 99.9 percent.

  A 95 percent overall level of H_2S control is assumed for new geothermal plants at The Geysers KGRA. Studies indicate that this should be possible, although successful long-term control has not yet been demonstrated. The hydrogen peroxide/iron catalyst system or the Stretford system with a secondary condensate treatment might achieve the required levels of control. Inherent limitations in these technologies, however, appear to justify continued pursuit of other alternatives (including those known as the EIC and Coury upstream systems).

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[5] Testimony of D. E. Morse (CEC Systems Assessment Office) before the California Public Utilities Commission. May 25, 1979.

While there could be problems in achieving these advanced levels of control, additional improvement in control technologies over the next decade could also produce emission levels lower than those projected. The staff considers the emissions levels and control assumptions in this study to represent reasonably expected future developments in energy production and emission control.

- Fuel Supply. Fuel type and quality are other factors which could result in variations from expected emissions. The availability (and regulatory approval for use) of natural gas is a key determinant, since emissions of major pollutants are significantly lower--orders of magnitude for some--for a facility burning gas rather than oil. Analyses comparing emissions from power plants burning projected amounts of available gas have been compared with emissions from plants complying strictly with federal regulations. If the regulations are left flexible enough to allow power plants to use gas, reductions in power plant emissions could be substantial in some areas of the state. In the future, power plants may also use cleaner-burning synthetic fuels, such as methanol.

- Electricity Demand. The actual rate of growth in electricity demand promises to have a profound effect on future air emissions from power plants. Generally, forecasts of demand growth have been declining in recent years, and supply plans have been adjusted accordingly. This study is based on the utilities' most recent forecast, roughly a 3 1/2 percent per year statewide average increase in electric generation. Variations from this forecast could be expected to change projected emissions levels significantly.

Air Quality Regulations

Air pollutant emissions from power plants fall into two categories: regulated and unregulated. There are ambient air quality standards or emissions limitations for regulated pollutants. They include nitrogen oxides (NO_x), sulfur oxides (SO_x), total suspended particulate matter (TSP), hydrocarbons (HC), and hydrogen sulfide (H_2S). Unregulated or "noncriteria" pollutants do not have standards or limitations, but are known, or are suspected to have adverse environmental effects. These pollutants include certain heavy metals, radioactive elements, and organic compounds.

Since the first federal air pollution legislation was passed in 1955, state and local governments have had the primary responsibility for preventing and controlling air pollution. In California, the State Air Resources Board (ARB) and local air pollution control districts share this responsibility. The Clean Air Act (CAA) of 1970, and as amended in 1977, established stronger legal mechanisms to deal with air pollution. Several specific programs were implemented under the umbrella of the Clean Air Act. These include: 1) National Ambient Air Quality Standards (NAAQS); 2) New Source Performance Standards (NSPS); 3) Prevention of Significant Air Quality Deterioration (PSD); and 4) New Source Review (NSR). The significance of these and other air quality regulations for electricity supply planning are summarized in Table 3. More specific comments on the applicability of these regulations to the utilities' plans for each air basin are discussed in the next section.

Air quality regulations such as those summarized in Table 3 are intended to achieve and maintain ambient air pollutant concentrations low enough to avoid

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Table 1

MAJOR AIR POLLUTION REGULATIONS APPLICABLE TO POWER PLANT PLANNING, SITING, AND OPERATION

	Regulation and effective date	Description	Effect on Power Plant Siting and Operation
1.	Federal-New Source Performance Standards (NSPS), amended June 11, 1979	Establishes maximum allowable emission levels for NOx, SOx, particulates and opacity from new and modified sources (including steam electric generators).	Little direct effects on new power plants in California. More stringent state and local regulations negate NSPS in most situations.
2.	Federal and State Ambient Air Quality Standards (AAQS), Clean Air Act 1970	Defines maximum allowable concentrations of pollution in the ambient air. Generally sets limits to protect public health with an adequate margin of safety.	Most power plants do not independently cause violations, although the standards can prevent siting in areas with existing air quality violations. Attainment of air quality standards is the primary reason for emission limitations, New Source Review, and other regulations.
3.	New Source Review (NSR) Regulations 1973-Clean Air Act Amendments 1977. (Mandated by Federal law enforced at the local level with ARB review).	To assure attainment and maintenance of ambient air quality standards, best available control technology (BACT) is required. Also, if a new emission source will cause or contribute to the violation of an AAQS, emission offsets (tradeoffs) are required to achieve a net air quality benefit.	The identification and use of BACT, subsequent plant efficiency loses, and equipment availability problems can add to utility costs. The non-availability of emission offsets can prelude plant construction in some instances. This is particularly true in rural air basins where pollution transport from urban areas cause violations downwind.
4.	Federal Prevention of Significant Deterioration (PSD), June 1, 1975 State (ARB) Air Conservation Program (ACP).	Defines the maximum permissible increments of air quality deterioration in all areas of the state. In Class I areas, such as national parks and wilderness areas, very little deterioration is permitted. Most of California is designated Class II, allowing slightly larger increments of deterioration. Class III areas allow air quality deterioration up to the national ambient standard.	Power Plants can be built in most Class II or III areas. Siting would be restricted in and around Class I areas. The distance which a plant must be from a Class I area, in order to not impact that area, would depend on the plant size, emission rates and transport characteristics of the area. Generally, 20 km (12 miles) is sufficient distance to avoid violations of PSD.
5.	Lewis Act (AB 250) January, 1977 applicable to the South Coast Air Quality Management District (SCAQMD) only.	Enables SCAQMD to levee "Emission fees" in conjunction with operating permits to cover the cost of district operation and requires annual renewal of operating permits.	Increasing fees being charged for permit renewal add to utility costs and can be burdensome particularly to the smaller municipal utilities.
6.	Air Pollution Control District (APCD) Air Quality Attainment Strategies (Effective date depends on the particular rule and District)	To achieve and maintain ambient air quality standards by specified dates, APCDs implement attainment strategies which incorporate a variety of methods to limit air pollution. These include the specification of Best Administrative and Technical Practices (BAATP) and Reasonably Available Control Methods (RACM).	Specific rules require utilities to employ designated strategies and methods intended to accomplish system-wide or plant-by-plant emission benefits. For example, SCAQMD Rule 1135.1 requires least NOx dispatch of in-basin power plants (as BAATP), while Rule 1109 of the same district limits the allowable fuel sulfur content as RACM for SOx control.
7.	Air Pollution Control District (APCD) Emission Limitations (effective date depends on the particular rule and district)	Emission limitations are rules which restrict the absolute mass-rate amount of pollution coming from any one source. The specific rules vary in form and strictness from one district to the next. Most rules, however, are patterned after "Rule 67" (L.A. County APCD, now part of SCAQMD). A complete list of these rules is contained in the CEC staff SIP comments (see reference #1)	Many adopted emission limitations are so stringent that only small stationary sources can be built. New power plants may be effectively prohibited in some districts. Some of there districts may be able to accommodate a power plant without detrimental air quality impacts given NSR requirements.
8.	California Air Pollution Emergency Plan adopted November 13, 1973	Provides for actions to be taken to prevent air pollution levels which could endanger public health. Individual APCD's develop and implement detailed plans. The applicable contaminents are Carbon Monoxide, Oxidant, Sulfur Dioxide and Sulfates. Three episode stages are generally defined with corresponding abatement actions to be initiated.	Abatement actions can include such things as requests of commercial and industrial users to reduce electricity consumption, and utilities to reduce electric power generation in the effected basin by importing power from outside the basin, and the requirement that natural gas or low sulfur fuels ([illegible]) be used in power plants. A stage 3 episode (emergency) may require utilities to reduce operation leaving demand unsatisfied (load shedding).

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Table-1

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MAJOR AIR POLLUTION REGULATIONS APPLICABLE TO POWER PLANT PLANNING, SITING, AND OPERATION

Regulation and effective date	Description	Effect on Power Plant Siting and Operation
9. SCAQMD Rule 1109 (proposed in 1978, and 1979, not adopted, but ARB staff is still studying).	This rule to control emissions of sulfur dioxide (SOx) would require that electric utility boiler use fuels with sulfur content of .1% or reduce the stack gas sulfur content to 60 ppm or less by January 1, 1985.	Increased cost to the utilities to obtain a .1% sulfur fuel or install flue gas desulfurization equipment. The installation of control equipment could require a great deal of capital expense, reduce unit efficiency and delay the retirement of otherwise marginal oil-fired units.**
10. SCAQMD Rule 1135.1 (previously 475.1), January 22, 1979, and Ventura County APCD Rule 59.1, May 24, 1979.	Rule 1135.1 required for SCE and LADWP: least NOx dispatch of all electric generating units, demonstration of 90% NOx reduction on a unit of at least 100 MW capacity by January 1, 1982 and a system-wide NOx reduction of 50% by December 31, 1982 and 90 by January 1, 1990. Rule 59.1 contains substantially similar provisions.	To comply with this regulation the utilities may need to implement combustion controls, low-NOx burners, or burn low nitrogen fuels, or retrofit catalytic DE-NOx equipment. As with Rule 1109 expensive modifications to old units may cause a utility to operate that unit beyond its normal lifetime to recoup its investment, thus continuing the dependance on old polluting oil-fired facilities.**
11. Proposed adoption of Rules	The ARB has suggested these rules may be necessary to achieve clean air standards in non-attainment areas.	The effect of these rules on power plants cannot be determined until the rules are more fully defined. It is likely, however, that most new rules would be modeled after SCAQMD Rules 431, 1135.1 and 1109.
By June 30, 1980	Oxides of nitrogen (NOx) from gas turbine generators: Santa Barbara, Ventura, San Diego, SCAQMD; Oxides of Sulfur (SOx) from electric utility boilers: SCAQMD, Ventura	
By December 31, 1980	NOx from electric utility boilers: San Diego; SOx from gas turvine generators: SCAQMD, Ventura; Particulate matter from electric utility boilers: SCAQMD, Ventura	
By June 30, 1981	SOx from electric utility boilers: San Diego; Sulfur content of fuel: San Diego; Particulate matter from electric utility boilers: San Diego	
By December 31, 1981	SOx from electric utility boilers: Kern, Monterey, San Luis Obispo; NOx from electric utility boilers: Kern, Monterey, San Luis Obispo; Particulate matter from electric utility boilers: Kern, Monterey, San Luis Obispo	

* The regulations examined here are only discussed with respect to their effect on electricity supply. Most of these, and many other specific air quality regulations impact all energy production and consumption sectors.

** Controlling emissions of NOx and SOx from electric utility power plants in the South Coast Air Basin has been estimated to cost one to two billion dollars in capital investments ($100 - 200 per KW) and 200 to 270 million dollars for operating costs (3 - 4 mills/kwh)--(1976-1978 dollars).

SOURCES

1. "Recommendations and Comments on the 1979 Revisions to the State Implementation Plan SIP," California Energy Commission, Biennial Report II (Docket NO. 78-BI-1).

2. Air Quality statewide Coal Plant Area screening study, California Energy Commission, Staff Draft, February 1979.

3. Crummie Maurice, "Air Pollution Retrofit Study: Emission Control for Oil-fired Power Plants in the South Coast Air Basin," Consultant Report, California Energy Commission, March 1979.

4. "California Air Pollution Emergency Plan," California Air Resources Board, March 24, 1977.

5. "Compilation of Air Pollution Control Regulations and Standards, California Energy Commission, June 8, 1976.

6. "Status Report on Sulfur Dioxide regulations for the South Coast Air Quality Management District" California Air Resources Board, September 21, 1978.

7. "Progress Report, Control Strategy for Oxides of Nitrogen in the South Coast Air Basin," California Air Resources Board, August 24, 1976.

unacceptable adverse environmental consequences. The main categories of such impacts, to which power plants are potential contributors, are:

- Public Health. Enforcement of existing standards and emissions limitations is presumed to adequately protect public health from regulated pollutants. If literally interpreted without change, these standards would effectively preclude implementation of Scenario IA, since the number of new coal plants required probably could not be sited in conformance with these requirements.

  The public is less protected against unregulated pollutants because the direct emission of these trace elements or compounds is not limited; therefore, technologies have not been developed to specifically control them. Further discussion of the public health risks associated with the utilities' plans for electric generation is the subject of a separate staff report (in preparation).

- Vegetation and Wildlife. The release of certain air pollutants from power plants can have significant effects on vegetation (both natural and cultivated) and wildlife; these include death, loss of resistance to disease, and reduced reproductive success. These effects can be classified based on the type of exposure causing them:

Acute:	Short-term, direct exposure (less than one month) to high concentrations of pollutants.
Chronic:	Longer term, direct exposure (several months to a year) to low concentrations of pollutants.
Long-Term:	Exposure of more than a year to low levels of pollutants as well as exposure to changes in soil characteristics,

water quality, species diversity, etc., caused by acute and/or chronic exposures.

Vegetation is most obviously affected by exposures to high concentrations of pollutants that occur over a short time during adverse meteorological conditions. Usually, animals are more seriously affected by chronic and long-term exposures. Pollution levels from the power plant and from other sources can have an additive or synergistic effect on plants and animals.

- Visibility. Increased power plant emissions in an air basin can reduce visibility. Visibility reduction is due primarily to particulates of a size which produces the greatest light-scattering effects, 0.4 to 0.7 microns. Particulates in this size range are either emitted directly by combustion-type generating facilities, or are formed in the atmosphere from NO_x, SO_2, and to some extent, hydrocarbons. These "precursors" form particulate nitrate and sulfate, and in humid atmospheres contribute to the formation of fog (fogging can also result from cooling towers). In addition, NO_x emissions are rapidly converted to NO_2 downwind from the source, and high levels of NO_2 result in a brownish discoloration of the atmosphere.

- Soiling and Corrosion. Pollution from the energy sector can soil surfaces and corrode various materials. Soiling is due primarily to particulate matter which settles out on clothing and structures. Alkaline or acid aerosols, especially sulfuric acid formed in the atmosphere from SO_2, can corrode or otherwise damage textiles, masonry, paint, and metals. Ozone, a particularly significant problem in California and the South Coast Air Basin, is damaging to rubber products and some synthetic textiles such as nylon. The life of products such as automobile tires and windshield wiper blades is significantly shortened in high-ozone areas.

Air Basin Implications

Under federally-required New Source Review (NSR) regulations,[6] construction of a new facility or modification of an existing facility would generally be prohibited if the facility emits significant quantities of pollutants which would cause or aggravate existing violations of air quality standards. However, the facility may be permitted if the developer can reduce the emissions from other pollution sources in the general vicinity of the proposed facility (or upwind of the site in the same or adjoining counties in the same air basin). These reductions (trade-offs) must more than offset the increased emissions from the new or modified facility. Consequently, the availability of trade-offs is a critical factor in determining the feasibility of constructing new facilities.

In most air basins where power plants are planned, emissions resulting from the utilities' plans contribute a relatively small portion of the total basin emissions from all sources.[7] In most cases, particulate emissions from power plants account for less than 10 percent of total particulate emissions in a basin while hydrocarbon emissions usually contribute less than 1 percent of total hydrocarbon emissions. Emissions of NO_x and SO_2 make a more significant contribution to total NO_x and SO_2 emissions in most instances.

Following are projections of power plant air pollutant emissions and a brief discussion of the implications for each air basin with prospective fossil-fuel or geothermal generation. Again, it should be noted that this assessment is irrespective of possible trade-offs which would offset emissions from new power plants by reducing those from other possible sources (including existing power plants). Air basins with no anticipated power plant emissions are not discussed.

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[6] The 1977 amendments to the Clean Air Act (Public Law 95-95, August 7, 1977).

[7] Historic and projected emission estimates for all nonpower plant sources were obtained from an ARB emissions inventory dated January 6, 1978.

North Coast Air Basin. The utilities' resource plans for this basin consist of expanding geothermal capacity from the present 608 MW to 1103 MW by 1991. A 500 MW coal facility is also included in Scenario IA. The principal air pollutant from geothermal facilities is H_2S. The state ambient standard for H_2S is now frequently exceeded in The Geysers KGRA, where all of the planned geothermal expansion in the basin will occur. Although H_2S trade-offs are not necessarily a condition for new plant construction, new facilities will have to comply with very stringent emission limitations which will require varying degrees of control. Additionally, emissions from all existing facilities will have to be reduced to meet ambient air quality attainment levels projected by ARB.[8]

Fossil-fueled plant emissions for all pollutants except SO_x account for a very small portion of total emissions in this basin (Fig. 6). However, it is highly unlikely that ambient SO_2 or sulfate standards are violated in this basin.[9] It is also unlikely that SO_x emissions from power plants will cause or aggravate any air quality problems. Other than making extremely small contributions to ambient particulate levels or SO_x emissions (which contribute to particulate formation), fossil-fueled power plants should have little impact on basin air quality.

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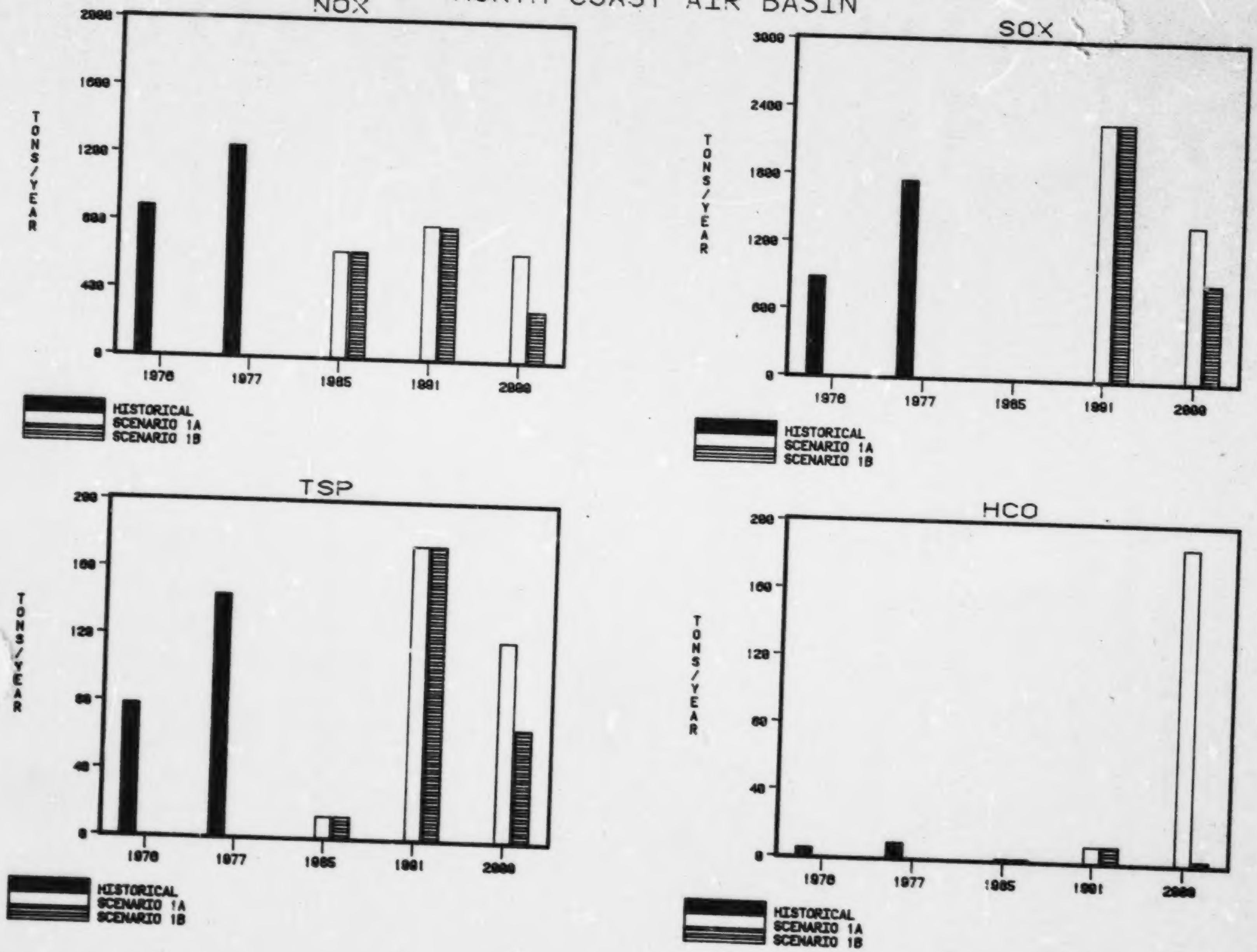
[8] For purposes of this analysis, all existing geothermal power plants are assumed to be retrofitted by 1985 with controls that reduce H_2S emissions by 90 percent while 95 percent control is assumed on a new plant. With these control levels, emissions would be about 600 lb/hr, well within the suggested ARB attainment levels of 180 to 360 kg/hr (396 to 793 lb/hr).

[9] Since these pollutants are not monitored in the basin, it is not absolutely certain whether there are violations.

Figure 6

AIR POLLUTANT EMISSIONS FROM POWER PLANTS
NORTH COAST AIR BASIN



The H_2S emissions (Fig. 7) estimates reflect the effect of a 90 to 95 percent H_2S emission control strategy in The Geysers KGRA: emissions of H_2S will decline from 7500 tons per year in 1976 to 1400 tons per year in 2000. Sites, however, will have to be chosen very carefully to prevent emissions from the new facilities from significantly affecting people and places downwind from the sites.[10]

Lake County Air Basin. Under current utility planning assumptions, 791 MW of geothermal capacity would be sited in this air basin by 1991; currently there are no operating electric generating plants. More than 700 tons of H_2S per year would be emitted in the basin assuming 95 percent abatement (Fig.8). The state ambient H_2S standard is frequently violated there due to the movement of H_2S from the North Coast Air Basin. However, with careful plant siting and full implementation of the planned H_2S-control strategy mentioned above, increased emissions in the Lake County portion of the KGRA should not violate ambient standards. This does not indicate, however, that each proposed facility will be found acceptable. No fossil fuel power plants are likely to be proposed in this basin.

Sacramento Valley Air Basin. This study assumes the location of PG&E's Fossil 3 coal-fired power plant to be in this basin. For the heavy coal case (Scenario IA), a second unit, Fossil 4, and several additional coal plant projects are assumed to be in the basin (Fig. 2).

Fossil 3 and 4 are expected to be able to comply with all applicable local emissions limitations in Butte County. However, state and federal ambient ozone and total suspended particulate (TSP) standards are presently exceeded and sufficient offsets for NO_x--an ozone precursor--are not available for a

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[10] Because of prevailing westerly winds, H_2S emitted in the North Coast Air Basin portion of The Geysers KGRA will generally settle to the east in the Lake County Air Basin.

Figure 7

HYDROGEN SULFIDE EMISSIONS FROM GEOTHERMAL POWER PLANTS
NORTH COAST

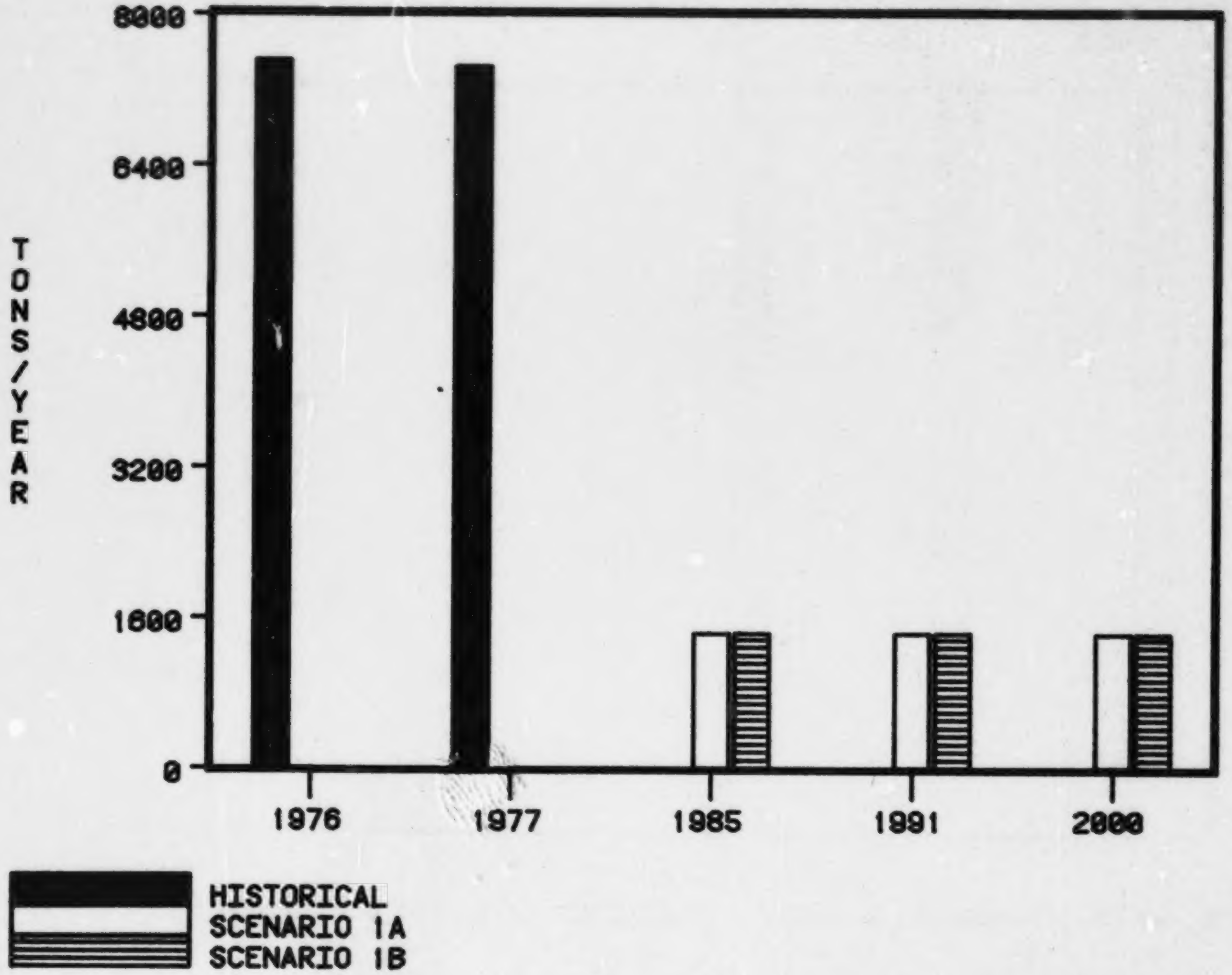
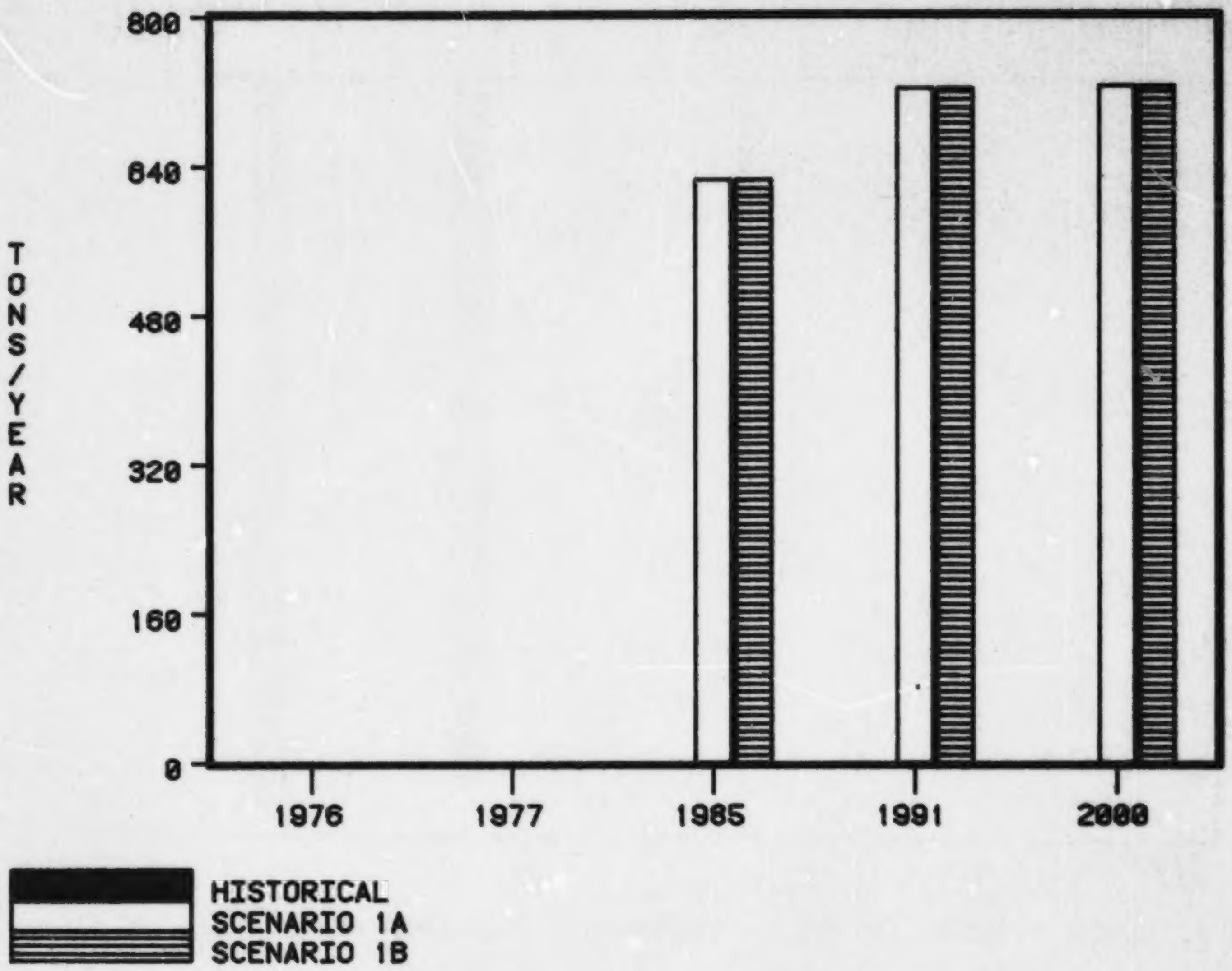


Figure 8



HYDROGEN SULFIDE EMISSIONS FROM GEOTHERMAL POWER PLANTS
LAKE COUNTY

facility of this size in the Sacramento Valley Air Basin. Without using selective catalytic reduction control equipment, NO_x emissions from the two units would be 20,200 tons per year, but with controls, they will produce only 1600 tons per year. Even so, the only possible source of sufficient trade-offs is the Bay Area Air Basin, and it is questionable, given the increases in fossil-fueled generating capacity planned for that basin, that enough offsets would be available to compensate for Fossil 3 and 4. Furthermore, state and local air pollution control agencies could decide against such an interbasin offset. The difficulties encountered in trying to build Fossil 3 and 4 in this air basin would be compounded with each additional facility assumed in Scenario IA.

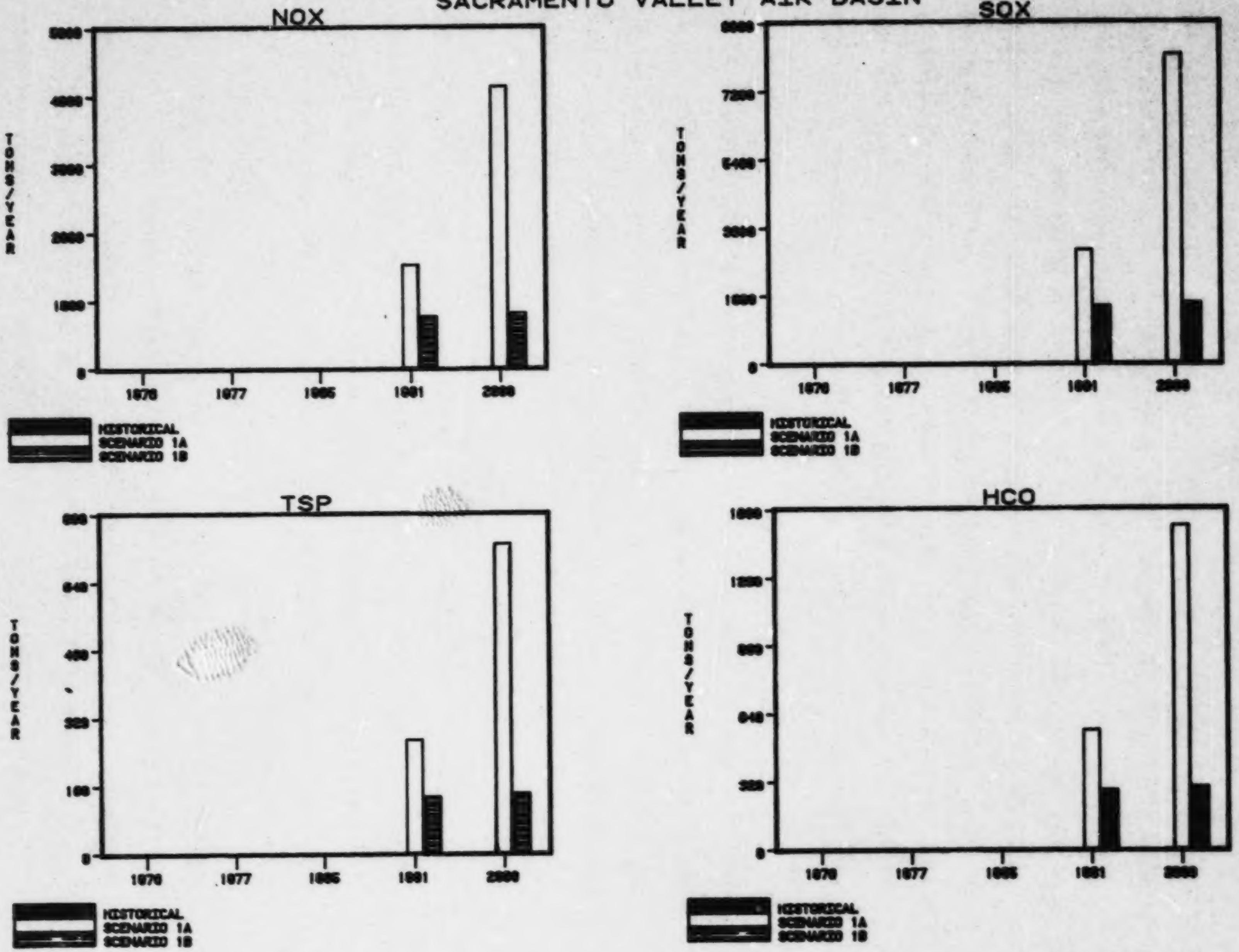
Emissions from the power plant sector would be relatively small in comparison with other sources, except for SO_2. Fossil 3 and 4 will produce 3200 tons of SO_x per year. However, since limited monitoring indicates no violations of SO_2 or sulfate standards, SO_x trade-offs would not be required except to the extent that SO_x (as a precursor) is a potential contributor to a particulate violation.

Since no fossil-fuel power plants currently exist in this air basin, any increase is significant (Fig. 9). The emissions in the year 2000 are about four times greater in Scenario 1A than in Scenario IB. In Scenario IB, only emissions from the Fossil 3 coal plant would occur; all other capacity in the basin would be nuclear.

Bay Area Air Basin. There would be a significant expansion of fossil-fuel generation capacity in the Bay Area Air Basin from the present 4473 MW to 8631 MW by 1991. This increase includes Fossil 1 and 2, Pittsburg 8 and 9, Potrero 7, and a number of cogeneration projects. An additional 1500 MW of coal-fired capacity by 2000 is also identified in Scenario IA. Federal and state

Figure 9

AIR POLLUTANT EMISSIONS FROM POWER PLANTS
SACRAMENTO VALLEY AIR BASIN



ambient standards for ozone and TSP, and state ambient standards for SO_2 and NO_2 are exceeded in portions of the basin. Local emission standards should not preclude power plant development in this air basin, but insufficient trade-off availability may. Trade-offs for NO_x, SO_2, total suspended particulates (TSP), and hydrocarbons would most likely be needed. The limited availability of NO_x trade-offs will probably be the most constraining factor.

The projected power plant emissions in this basin (Fig. 10) reflect the operation of both new and existing facilities (with some retired). Despite the addition of new generation, total power plant emissions (except HC) in the basin are not expected to increase due to the cleaner operation of new plants. If natural gas could be used, SO_x and particulate emissions could even be reduced. Although HC emissions from power plants would increase, the contribution to total basin hydrocarbons would remain small.

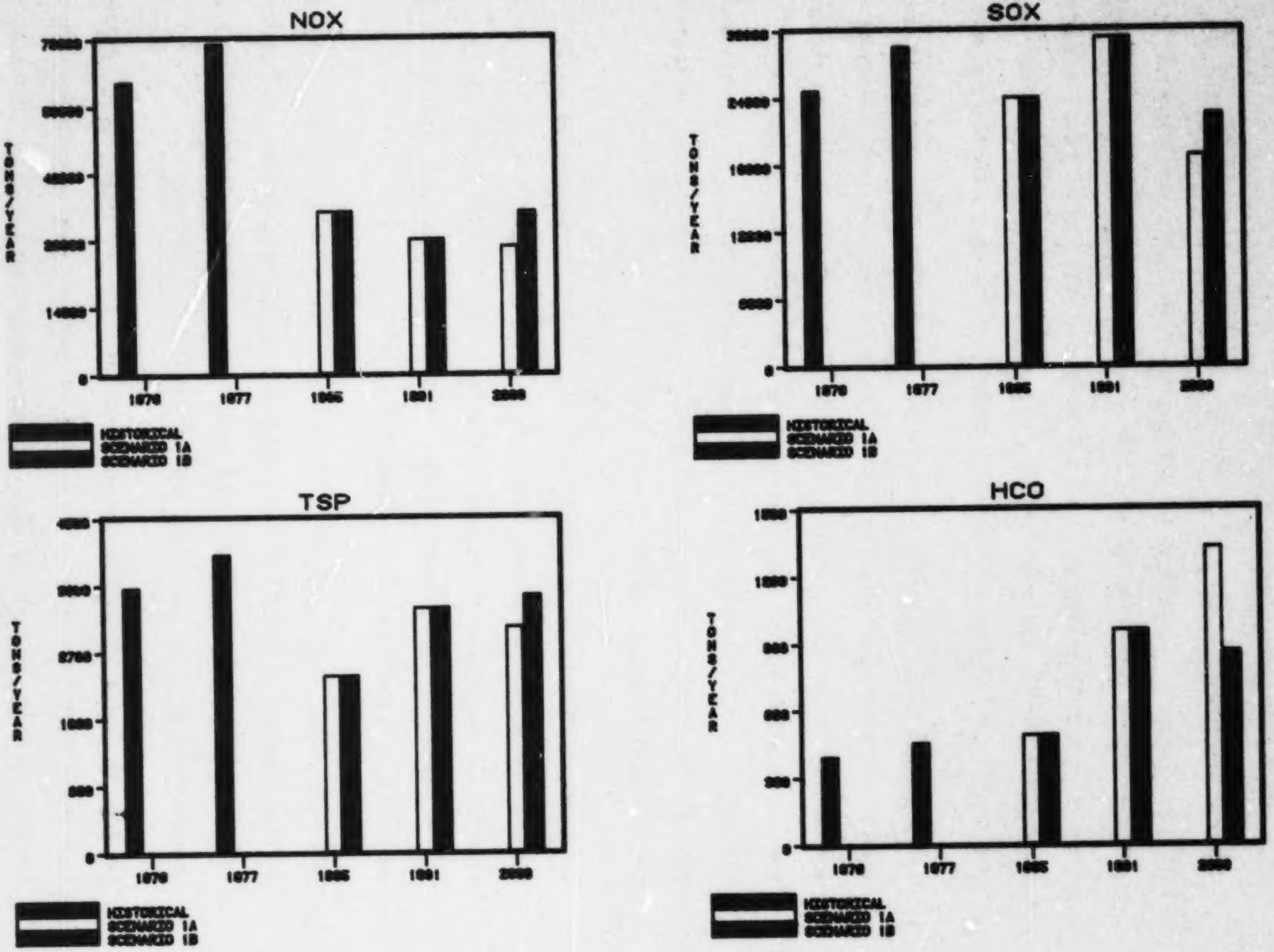
Emissions of NO_x which contribute to the basin's ozone problem as well as to the ambient NO_2 problem, would be reduced. Emissions of SO_x should continue to contribute to an ambient SO_2 problem in Contra Costa County. On the whole, the relative contribution of power plants to the total basin NO_x emissions decreases considerably from 1976 through 2000.

Emissions of NO_x, SO_x, and TSP in 2000 are higher in Scenario IB. Since the nuclear capacity in Scenario IB provides less energy than the new coal capacity in IA, the existing oil system must operate more, emitting more pollution per megawatt-hour than the new, clean coal units.

San Joaquin Valley Air Basin. Several small or mid-sized fossil-fueled cogeneration facilities are planned in the basin by 1991, increasing total capacity by 355 MW. By 2000, Scenario IA would add 6000 MW of coal capacity; IB represents

Figure 10

AIR POLLUTANT EMISSIONS FROM POWER PLANTS
SAN FRANCISCO BAY AREA AIR BASIN



12,000 MW of nuclear additions. The entire basin currently exceeds state and federal ambient ozone and TSP standards, and portions of the basin violate the state and federal ambient SO_2 standards and the state sulfate standard. With the large industrial base (oil field production), there should be sufficient trade-offs available to meet the New Source Review requirements for some facilities. However, local emission standards throughout the basin are very restrictive. They consist largely of the old Los Angeles County Air Pollution Control District's Rule 67-type of emissions limitations.[11] These standards only allow very small boilers (less than 100 MW) burning low sulfur distillate, or very clean combustion turbine units (about 40 MW or less) using water injection. The standards could interfere with siting the planned cogeneration capacity if the necessary control technology and/or clean distillate (or natural gas) were not available.

Many if not all of the coal-fired units in Scenario IA could probably not be built in this basin if current regulations and air quality problems persist. If the coal plants were built as assumed, the amount of NO_x, SO_x, and particulate emitted by power plants in the basin would more than double; and HC would increase by nearly two orders of magnitude (Fig. 11). The power plant contribution to total basin emissions of each pollutant would increase dramatically. If Scenario IB was implemented, the power plant contribution to basin emissions would be reduced, or increase very slightly from present levels.

North Central Coast Air Basin. Generating capacity changes in this air basin consist of several new, small cogeneration projects (in conjunction with other industries) through 1991, followed by the retirement of some existing oil-fired units. In Scenario IA, one 500 MW coal-fired plant is added by the year 2000.

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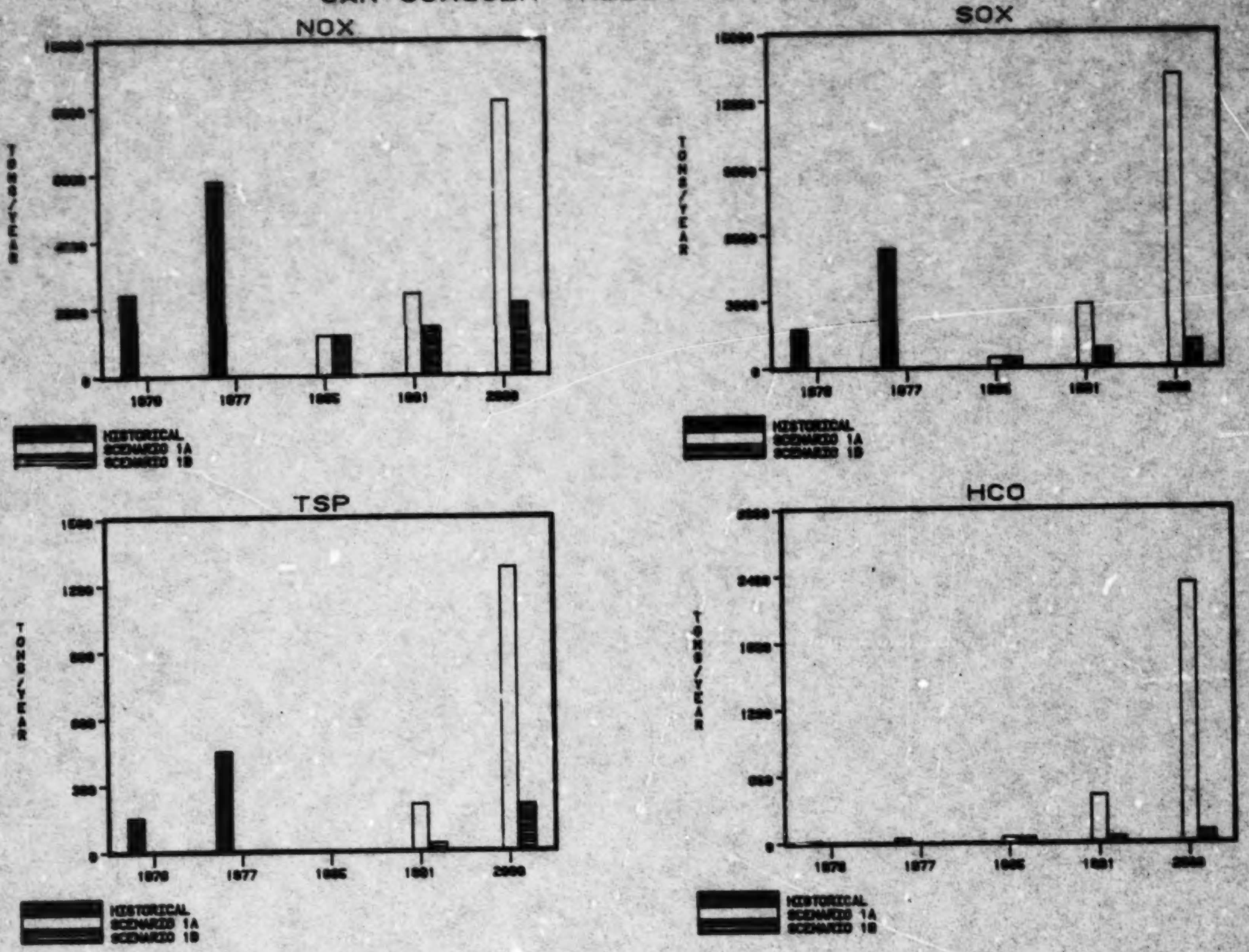
11. Emission limits of 10 lb/hr for particulates, 140 lb/hr for NO_x, and 200 lb/hr for SO_2.

Figure 11

AIR POLLUTANT EMISSIONS FROM POWER PLANTS
SAN JOAQUIN VALLEY AIR BASIN



Currently, federal and state ambient ozone and the state ambient TSP standards are exceeded. Emissions of NO_x from existing power plants probably aggravate the ozone standard violations. However, such emissions are projected to decrease by two-thirds by the 2000 (Fig. 12). Furthermore, NO_x trade-offs for new projects should be available, but it may be difficult to comply with the local APCD's emission limitation for NO_x. Power plant emissions of SO_x may contribute slightly to ambient TSP standard violations due to conversion of SO_2 to particulate sulfate in the atmosphere. Both SO_x and particulate emissions are expected to increase sharply in 1991 when natural gas can no longer be used in the older units; however, they will decrease as units are retired and new capacity provides cleaner energy.

In 2000, NO_x, SO_x, and particulate emissions should be lower in Scenario IA than in IB since the new coal-fired units in IA provide more energy than the new nuclear units in IB; the energy difference in IB must be made up using older, more polluting, oil-fired units.

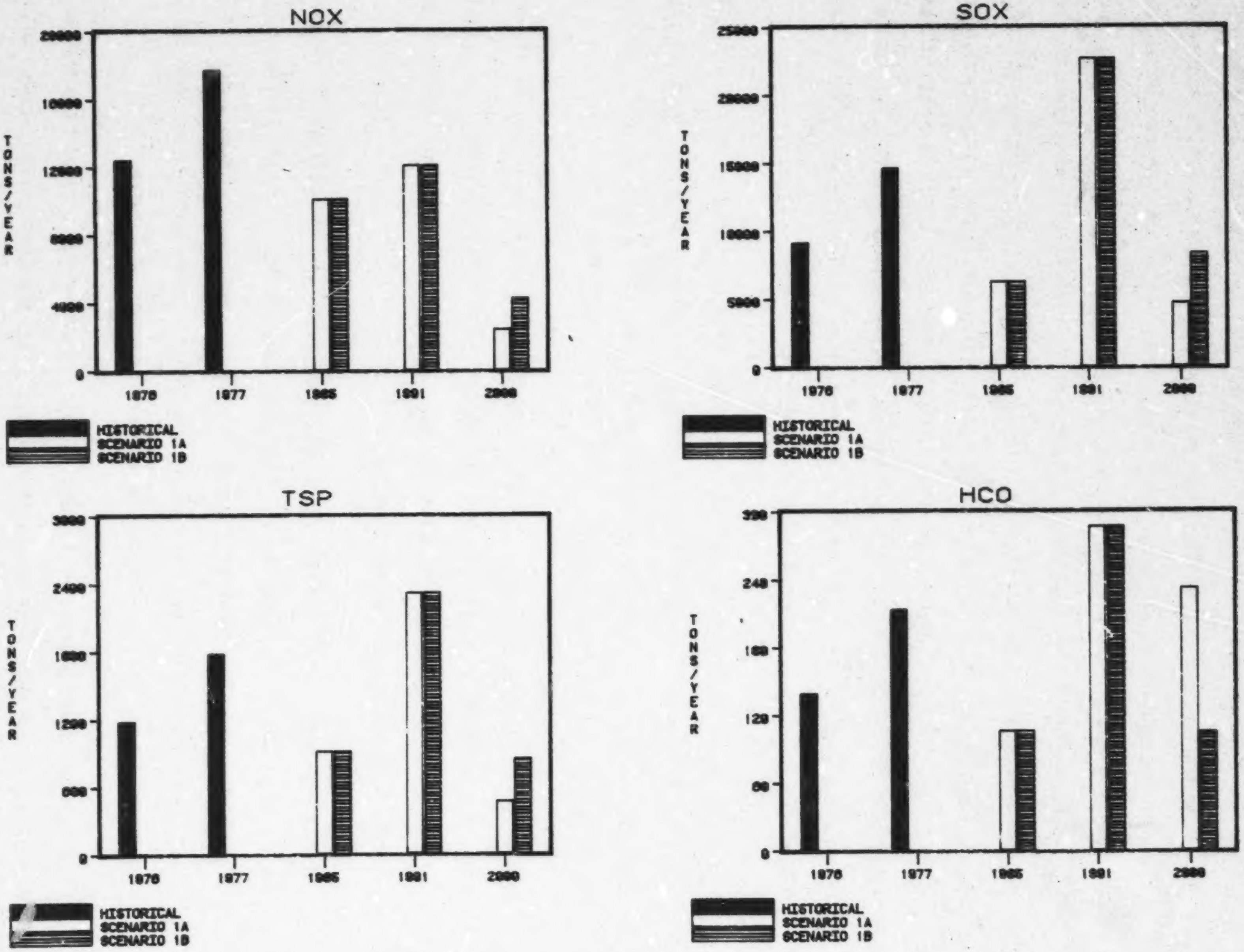
South Central Coast Air Basin. Diablo Canyon Nuclear Generating Station is the only new capacity planned for this air basin before 1991. However in Scenario IA, 2500 MW of new coal capacity is assumed by the year 2000; Scenario IB assumes 1300 MW of new nuclear capacity.

Both state and federal ambient ozone and TSP standards are exceeded throughout the basin; and in Ventura County, the state ambient NO_2 standard is exceeded. Rule 67-type emission limitations are in effect throughout the basin, restricting fossil fuel-fired generation to very clean units, such as a very small boiler or a very clean combustion turbine or combined cycle plant.

The role of power plants in the overall air quality picture is perhaps the most significant in this basin. During much of the planning period, power plant

Figure 12

AIR POLLUTANT EMISSIONS FROM POWER PLANTS
NORTH CENTRAL COAST AIR BASIN



emissions will comprise over a quarter of the NO_x, over a fifth of the SO_x and about a tenth of the particulates emitted in the basin. These emissions, particularly NO_x and SO_x, will contribute to the ozone, NO_2, TSP, and sulfate standard violations in the basin. By 2000 however, all pollutants--except HC in Scenario IA--are reduced from present levels (Fig. 13). Emission reductions would occur sooner if natural gas could be used in old facilities.

The implementation of Ventura County Air Pollution Control District (APCD) Rule 59.1 (not simulated for this study) should reduce present levels of NO_x emissions from power plants in Ventura County by about 50 percent in 1985, and 90 percent in 1991 and 2000. Even with decreased NO_x emission levels in the air basin by 2000, it appears that, based on the utilities demand forecasts, additional controls will be needed on existing units to comply with Rule 59.1. It is uncertain whether the required control levels can be attained.

South Coast Air Basin. The only additional generation capacity planned for this basin by 1991 is 390 MW of fuel cells and 150 MW from rerating--increasing the rated capacity of an existing facility--Scattergood 3. Scenario IA identifies 2500 MW of new coal capacity by the year 2000.

Nearly all state and federal ambient standards are exceeded in the basin. However, trade-offs for new projects should be available, and local emissions limitations could most likely be met.

Power plant emissions make up a fairly large fraction of total basin SO_x and particulate emissions. Consequently, power plants have contributed significantly to the air quality problems of the basin, especially problems with SO_2 and sulfate. The relative contribution of power plant NO_x, SO_x, and TSP emissions should decline steadily in future years due largely to the reduced use of older, in-basin plants (Fig. 14).

Figure 13

AIR POLLUTANT EMISSIONS FROM POWER PLANTS
SOUTH CENTRAL COAST AIR BASIN

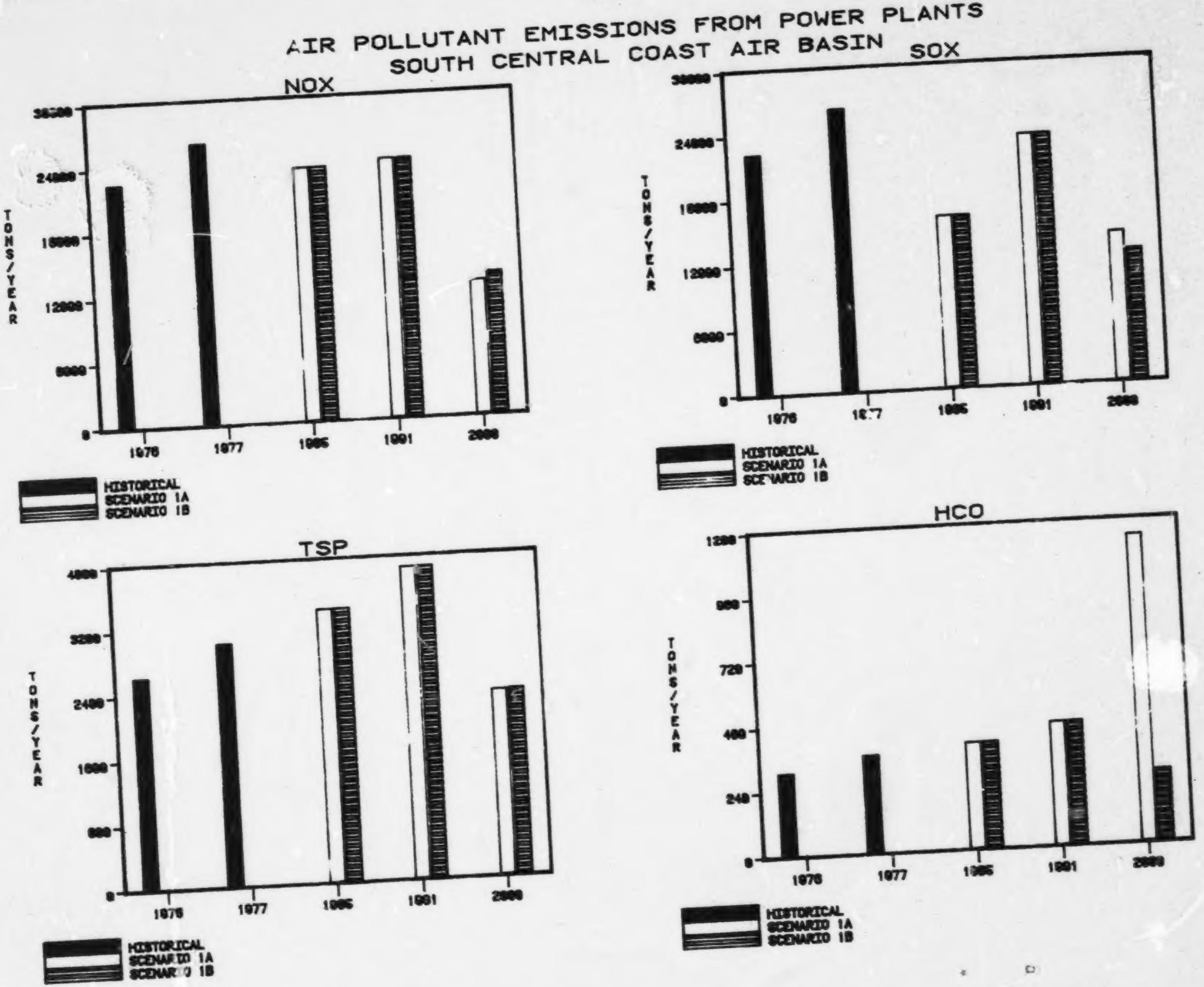
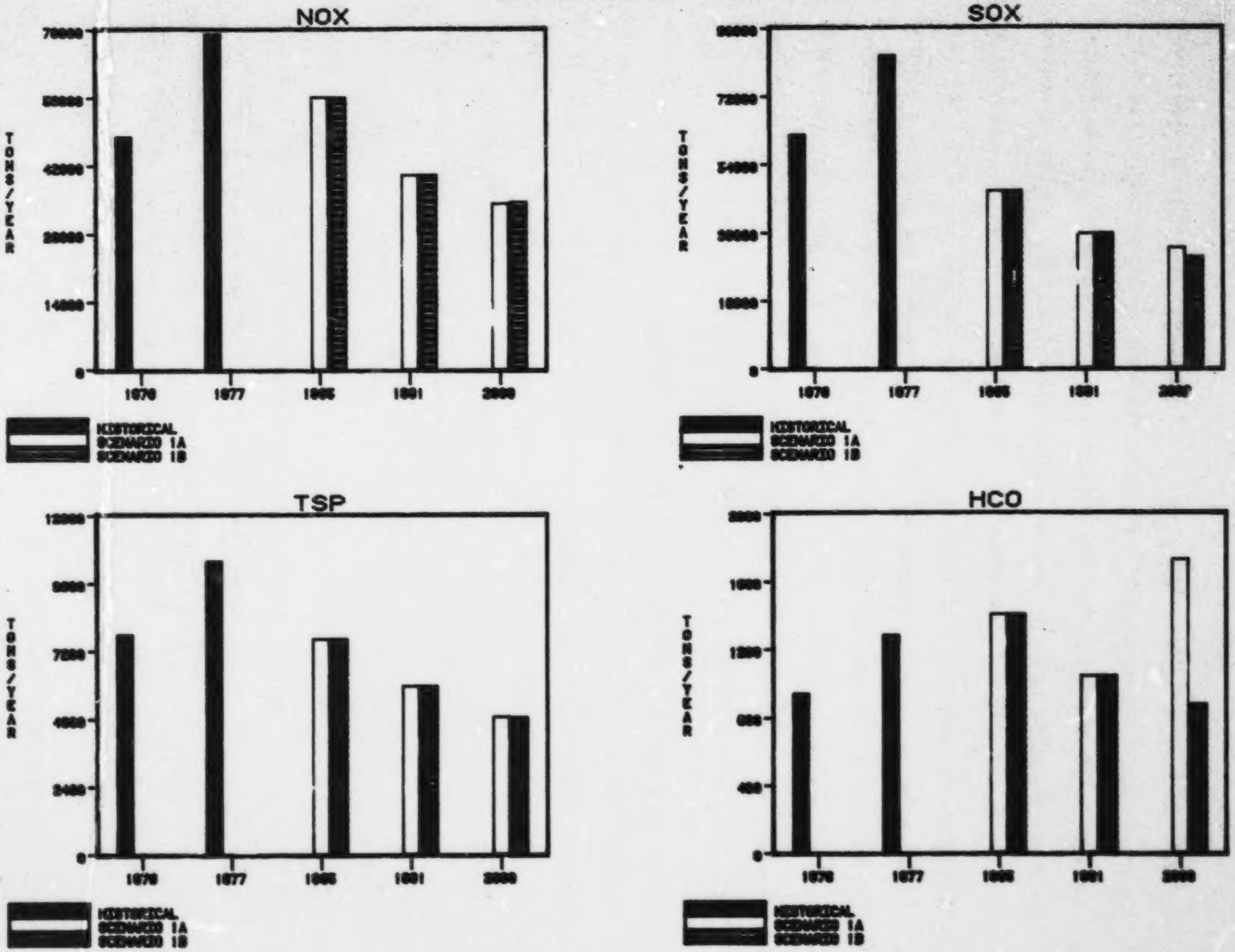


Figure 14

AIR POLLUTANT EMISSIONS BY POWER PLANTS
SOUTH COAST AIR BASIN



As with Rule 59.1 in Ventura County, the South Coast Air Quality Management District (SCAQMD) Rule 1135.1[12] was not simulated in this study. The rule, although being modified, requires power plant emissions of NO_x to be reduced by about 50 percent in 1985 and 90 percent after 1990; the ability to achieve these reductions is not demonstrated. The application of control technologies to reduce NO_x emissions would add to the cost of electricity. Also, the cost of retrofitting control equipment on old, oil-fired units may require a utility to continue to operate an otherwise marginal unit to recoup its investment. Considering the trend toward lower NO_x emissions, the additional reductions possible through energy conservation, and the replacement of old facilities, the need for such a stringent rule has not been demonstrated.

Southeast Desert Air Basin. Plans for this basin include 800 MW of liquid-dominated geothermal power plants and 2790 MW of new fossil-fuel facilities by 1991[13]. Between 1991 and 2000, another 700 MW of geothermal and 5500 MW of coal-fired capacity will be located in the basin in Scenario IA. In Scenario IB, 3900 MW of nuclear capacity replaces the coal from Scenario IA. In both scenarios, this basin would face increased emissions from power plants with subsequent impacts on air quality (Fig. 15 and 16).

The geothermal power plants will be located in the Imperial Valley where the state ambient H_2S standard is presently violated, presumably due to agricultural practices. Geothermal power plants can be expected to contribute to these ambient H_2S levels since none of the geothermal power plants presently planned have pollution control equipment. After the intitial demonstration facilities are proved, New Source Review regulations will probably

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[12] Formerly Rule 475.1.

[13] This includes the SCE Combined Cycle and California Coal Projects, both of which have candidate sites in other air basins as well.

Figure 13

AIR POLLUTANT EMISSIONS FROM POWER PLANTS
SOUTHEAST DESERT AIR BASIN

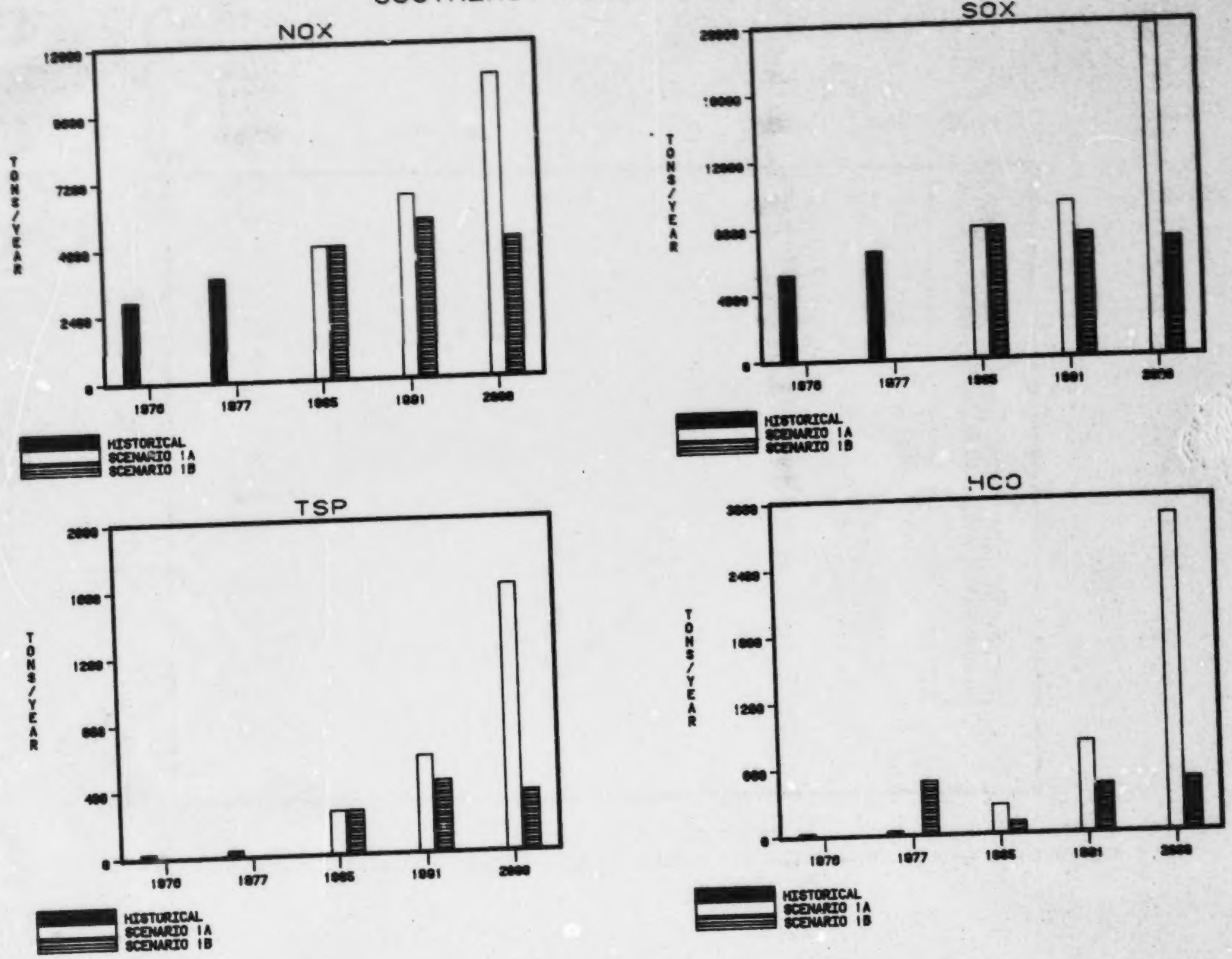
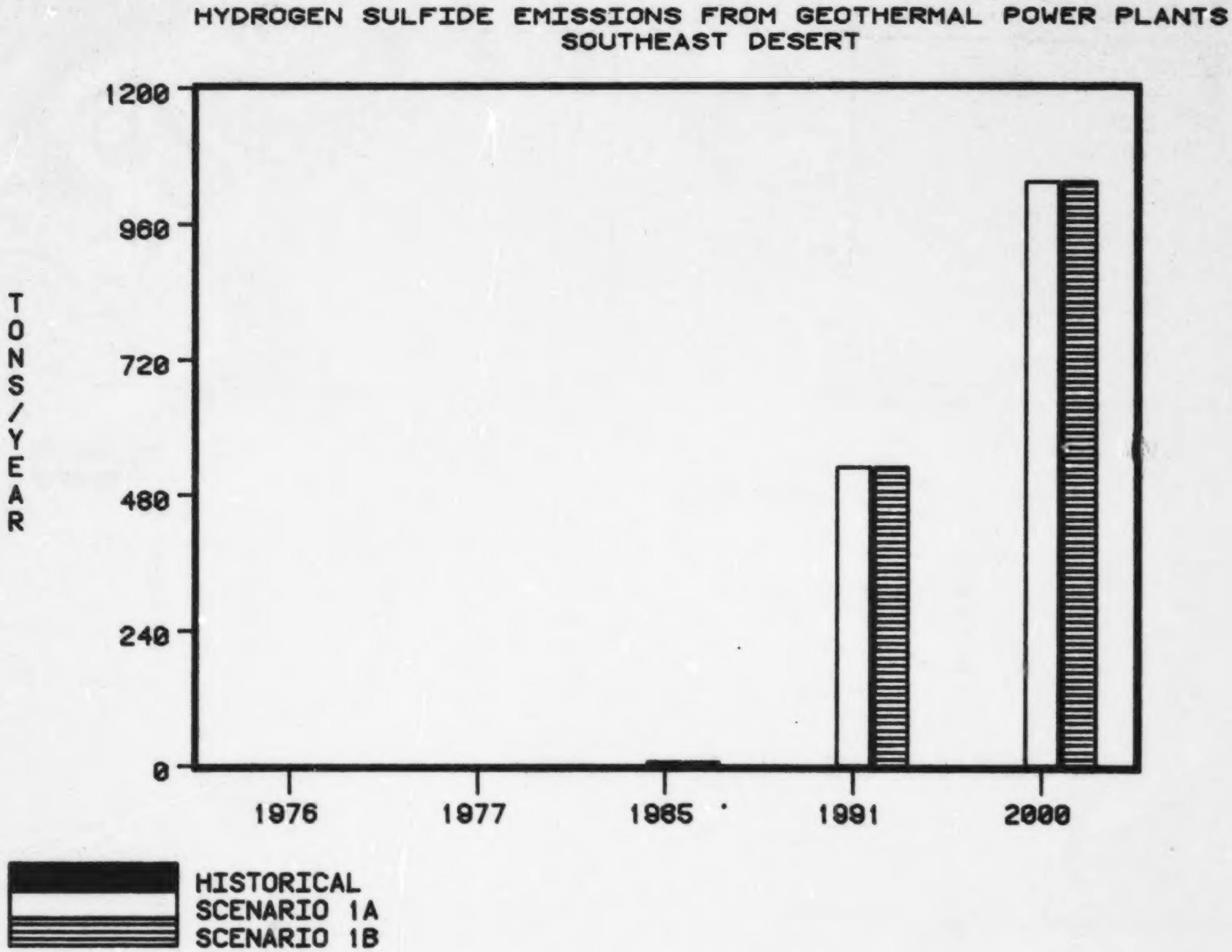


Figure 16


HYDROGEN SULFIDE EMISSIONS FROM GEOTHERMAL POWER PLANTS
SOUTHEAST DESERT
TONS/YEAR
1200
960
720
480
240
0
1976
1977
1985
1991
2000
HISTORICAL
SCENARIO 1A
SCENARIO 1B

require some controls. Because air pollution control systems for liquid geothermal power plants are in the experimental stage of development, it is not yet possible to know the degree or type of control which will be available or required for these facilities.

Fossil-fuel plants face more serious and certain obstacles. State and federal ambient ozone and particulate standards are violated in most of the basin. Obtaining necessary trade-offs will be difficult; where existing polluters are causing violations, the local nonattainment plans require reductions which prevents those reductions from being used as trade-offs; where violations are caused by pollution from other areas, there are no polluters from which trade-offs would be available. In addition, Rule 67-type emission limitations are still recognized by the U.S. Environmental Protection Agency as being in effect, making it very difficult to construct any fossil-fueled facility other than a very small boiler, or a very clean combustion turbine or combined-cycle unit. Finally, Prevention of Significant Deterioration (PSD) regulations may preclude many future siting options. Although PSD requirements must be reviewed in every power plant siting case, the Southeast Desert is the only air basin where problems appear imminent. At present, most of the basin is designated as Class II for air quality regulation purposes; this allows increases in emissions that are compatible with the siting of new power plants. The United States Bureau of Land Management has designated large areas of the basin as Wilderness Study Areas which holds the possibility that much of the Southeast Desert Air Basin will be redesignated from Class II to Class I. The Class I designation is used for areas such as national parks where little or no increase in air pollution is allowed.

San Diego Air Basin. Only new nuclear generation capacity (San Onofre Units 2 and 3) is planned in this basin through 1991. Beyond 1991, a number of plants will be retired, and two 500 MW coal units will be added in Scenario IA. The

San Diego Air Basin has serious air quality problems. Ambient ozone, sulfate, particulate and NO_2 standards are being violated. In 1991, emissions of NO_x from power plants will constitute less than 20 percent of the basin's total NO_x emissions which contribute to the ozone and NO_2 violations. Power plant emissions of SO_x are a major part of the basin's total emissions of that pollutant. Power plants must, therefore, bear a major part of the blame for sulfate standard violations. By the year 2000, emissions of NO_x, SO_x, and TSP from power plants in the basin are projected to diminish slightly because existing plants will be used less often as they are replaced by out-of-basin energy sources (Fig. 17). In the interim, SO_x and TSP emissions could be reduced if clean fuels could be used.

Northeast Plateau Air Basin. This air basin presently has no electric generation facilities other than hydroelectric plants. New generation expected in the basin is limited to one small cogeneration facility and, in Scenario IA, 500 MW of coal-fired capacity. Since no emissions are presently released by power plants, any increases are significant (Fig. 18).

Presently, air quality is not monitored in this basin; therefore, the basin is unclassified with respect to federal air quality nonattainment, and Federal New Source Review (NSR) regulations and trade-offs would probably not be required. Only federal "prevention of significant deterioration" regulations or local emission limitations might constrain power plant siting.

Out-of-State. California utilities expect to own new coal-fired and nuclear capacity located in Utah, Nevada, New Mexico, and Arizona. There is reason to believe that these coal projects could comply with emissions limitations in these states because the limitations will not be as strict as those which must be met by Fossil 1 and 2 and other coal projects planned in California.

Figure 17

AIR POLLUTANT EMISSIONS FROM POWER PLANTS
SAN DIEGO AIR BASIN

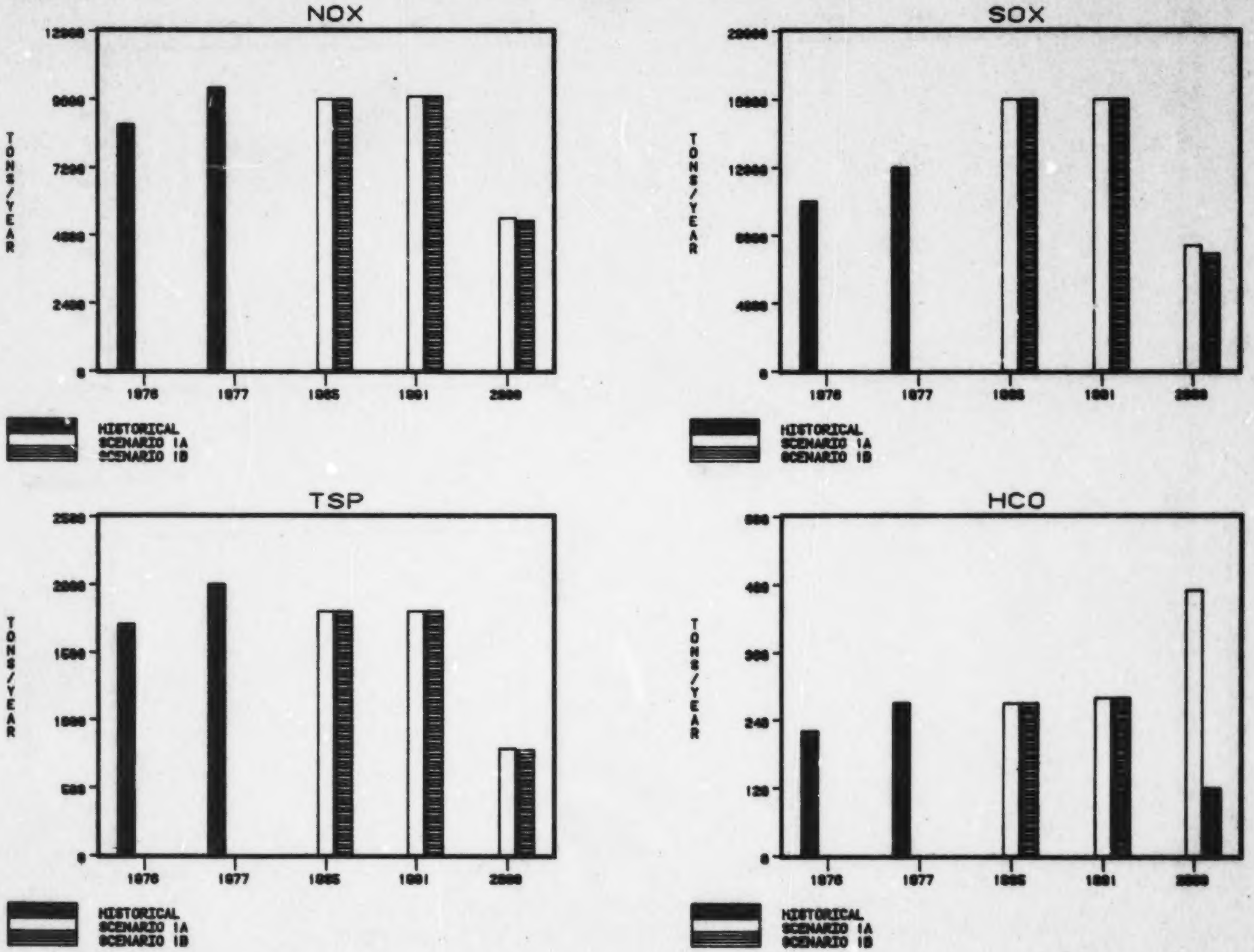
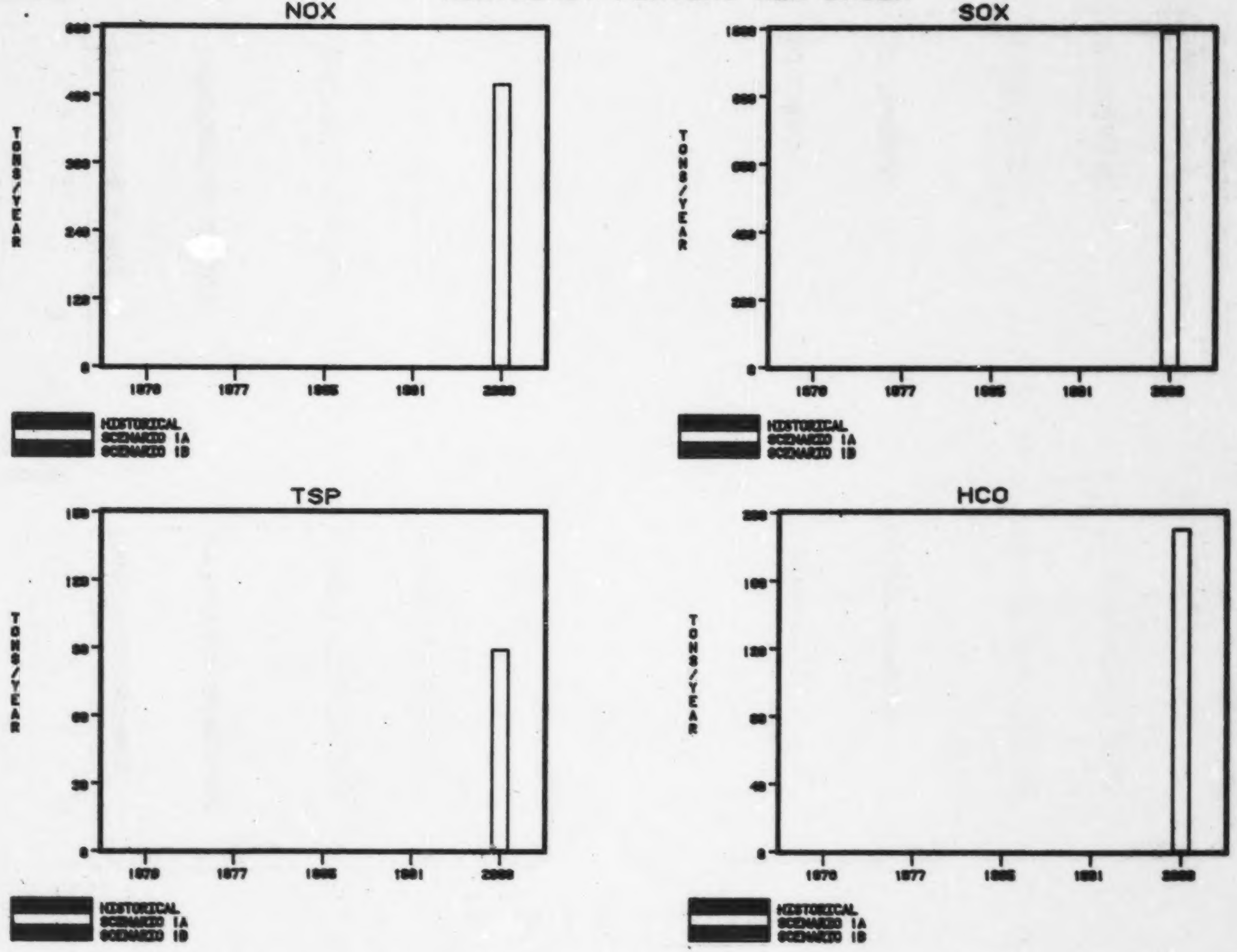


Figure 18

AIR POLLUTANT EMISSIONS FROM POWER PLANTS
NORTHEAST PLATEAU AIR BASIN



Compliance with federal New Source Review regulations is uncertain. But federal and state ambient air quality standards are not being violated in the siting areas of greatest interest, so trade-offs might not be required. The Prevention of Significant Deterioration (PSD) regulations will constrain coal plant siting because, there are a considerable number of Class I areas particularly in southern Utah near several proposed power plant sites.[19] This could inhibit the construction of large coal-fired facilities unless they are optimally located and use extremely efficient emission control technology such as Fossil 1 and 2 will employ.

Emissions of NO_x and hydrocarbons from out-of-state power generation serving California will increase most significantly (Fig. 19). Increased efficiency of controls for SO_x and particulates is responsible for the relatively small total increases in these pollutants as new plants are built.

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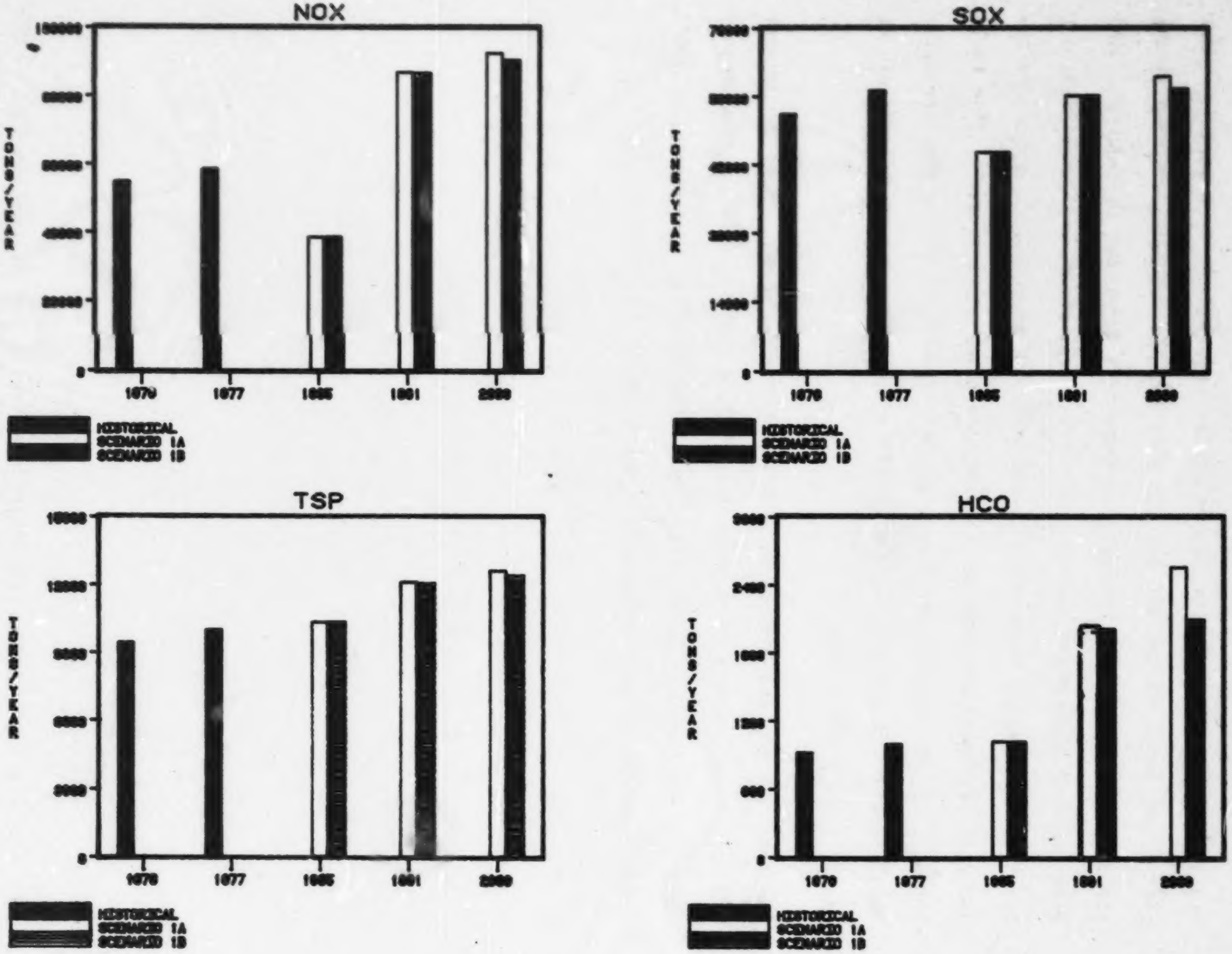
[19] Only slight air quality deterioration is permissible in Class I PSD areas.

Figure 19

AIR POLLUTANT EMISSIONS FROM OUT OF STATE GENERATION SERVING CALIFORNIA



IV. WATER RESOURCES

Operation of the utilities' existing and planned electric generating facilities will have a variety of effects on water resources due to requirements for condenser cooling water supply and residual substances produced. These might present significant issues with respect to the types and locations of new power plant projects, or might be resolvable on a case-by-case basis with available mitigation methods. The major water-related features of the generation technologies for which the utilities are planning projects are compared and summarized in Table 4.

Water Supply

The utilities' current plans dramatically illustrate the move toward inland siting for new generating facilities, due primarily to coastal siting restrictions. With few exceptions (including the Diablo Canyon and San Onofre Nuclear Projects now nearing completion), the utilities appear prepared to forego additional reliance on coastal siting, and the water supply and efficiency advantages of ocean once-through cooling.

Southern California Edison Company identified two existing coastal power plant sites (Huntington Beach and Ormond Beach) as candidate locations for its Combined Cycle and/or California Coal Projects. However, there are also several prospective inland sites for these projects. Existing plants can sometimes be repowered to add generating capacity on the coast, but this is of minimal importance in the current supply-planning picture.

Present (1978) and planned (2000) generating systems of the California utilities can be compared with respect to the need for cooling and type provided for. Generating capacity with cooling towers is projected to increase substantially

Table-4

Water-Related Characteristics of Generating Facilities Planned by California Utilities

Generation Type	Cooling Water Requirements[1]		Other Water Requirements gal/kWh	Major[2] Waste Water Effluents	Other Water Quality Concerns
	Evaporative Loss gal/kWh	Blowdown gal/kWh			
Coal	.50	.06-.50	.02-.08[3]	Cooling tower blowdown Boiler blowdown Cleaning operations Coal pile run off	Ash and sludge disposal
Nuclear	.67	.07-.67	.01	Cooling tower blowdown Boiler blowdown Cleaning operations	Liquid radionuclide releases
Combined Cycle	.20	.02-.20	.05[4]	Cooling tower blowdown Boiler blowdown Cleaning operations	Fuel oil spills
Gas Turbines	None	None	.07[4]	Cleaning operations	Fuel oil spills
Geothermal (Vapor)	(Supplied by geothermal fluid)		Negligible	Cooling tower blowdown (reinjected)	Site erosion, fluid spills
Geothermal[5] (Liquid)	2.7	.30-2.7	Negligible	Cooling tower blowdown (reinjected)	Fluid spills
Cogeneration[6]	—	—	—	—	—
Fuel Cells	None	None	Negligible	None	None
Wind	None	None	Negligible	None	None
Solar(Steam)	1.0	.11-1.0	Negligible	Cooling tower blowdown Boiler blowdown Cleaning operations	None
Hydro-electric	None	None	Negligible	None	Streamflow impoundment

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1/Make-up water requirements for evaporative cooling towers. Blowdown range based on 2-10 cycles of cooling water concentration (lower cycles = more blowdown). Facilities located on the coast would require from 20 to 40 gal/kWh of sea water for once-through cooling.

2/For facilities located on the coast, once-through cooling system thermal effluent would replace cooling tower blowdown.

3/If cooling water supply quality is adequate, cooling tower blowdown can be recycled to reduce net additional plant water requirements to the lower number.

4/Where water (or steam) injection for NO_x control is employed.

5/Due to requirements for total reinjection of fluids (because of potential land subsidence) liquid-dominated geothermal projects in the Imperial Valley are expected to need outside sources of cooling water.

6/Most planned cogeneration projects will operate in conjunction with industrial processes (including thermal-enhanced oil recovery), with no additional water requirements or waste water effluents attributable to the generation component.

as compared with capacity using once-through cooling or not requiring cooling. Projections for the year 2000 are based on extending the utility plans with emphasis on either coal-fired or nuclear plants (Scenario IA and IB, respectively). They reflect the more likely prospect of renewed coastal siting activity in the coal case rather than the nuclear case (See maps of potential siting areas in Appendixes A1 and A2.)

Projected Water Requirements. About 40,000 MW of the total 45,000 MW of capacity additions called for in the utilities plans by the year 2000 could be steam-electric facilities, which require condenser cooling (Table 5).[15] Even more significant is the fact that up to 38,500 MW of this new steam-electric capacity is likely to be located inland using evaporative cooling towers.[16] Due to their requirements for cooling tower make-up water supplies, facilities in this category present the major problems with water resources in the utilities' plans.

Projections of these water requirements, obtained using the CEC staff's "residuals model,"[17] are shown in Figure 20 distributed geographically based on the Hydrologic Study Areas (HSA) of the state (see map, Figure 21). When compared with the present level of water use by power plant cooling towers in the state (also shown), the 1991 projection of 122,000 acre-feet per year (AFY) represents over a three-fold increase in water needs for this purpose. By the year 2000,

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[15] This includes 3,500 MW of geothermal facilities; 2,000 MW of vapor-dominated plants (e.g., Geysers) expected to supply their own cooling water from geothermal fluid, and 1,500 MW of liquid-dominated plants expected to require an outside water source so that 100 percent reinjection of fluid can be maintained.

[16] Although wet tower cooling has not yet been specifically identified for all planned projects, this method is the utilities' clear choice to date for inland facilities.

[17] The cooling water calculation component of the model is described in a paper entitled: "Modeling of Make-Up Water Requirements for Power Plant Cooling Towers," T. MacDonald, CEC, January 1979.

Table-5

TYPES OF COOLING EMPLOYED BY ELECTRIC GENERATING FACILITIES*

(MW)

	Total Installed Capacity			Once Through Cooling			Cooling Towers			No Cooling Requirements		
	1978	2000		1978	2000		1978	2000				
		1A	1B		1A	1B		1A	1B			
Hydro-Electric	7,300	9,400	9,400	-	-	-	-	-	-	7,300	9,400	9,400
Oil/Gas												
Steam Turb	21,900	17,700	17,700	18,300	15,200	15,200	3,600	2,500	2,500	-	-	-
Comb Turb	1,400	1,900	1,900	-	-	-	-	-	-	1,400	1,900	1,900
Combined Cycle	600	4,400	4,400	500	-	-	100	4,400	4,400	-	-	-
Nuclear	1,400	6,500	32,300	500	4,900	6,200	900	1,600	26,100	-	-	-
Coal	2,500	34,899	8,199	-	6,000	-	2,500	28,900	9,100	-	-	-
Geothermal												
Vapor	500	2,000	2,000	-	-	-	500**	2,000**	2,000**	-	-	-
Liquid	-	1,500	1,500	-	-	-	-	1,500	1,500	-	-	-
Cogeneration	300	1,700	1,700	-	-	-	-	-	-	300	1,700	1,700
Wind	-	400	400	-	-	-	-	-	-	-	400	400
Fuel Cells	-	200	200	-	-	-	-	-	-	-	200	200
Solar	-	500	500	-			-	500	500	-	-	-
Total	35,900	81,100	81,100	19,300	26,100	21,400	7,600	41,400	46,100	9,000	13,600	13,600

* Includes plants in California plus out-of-state capacity owned by California utilities.

** Cooling Tower water requirements supplied with geothermal steam condensate.

Figure 20

COOLING TOWER WATER CONSUMPTION FOR POWER PLANTS
BY HYDROLOGIC STUDY AREA

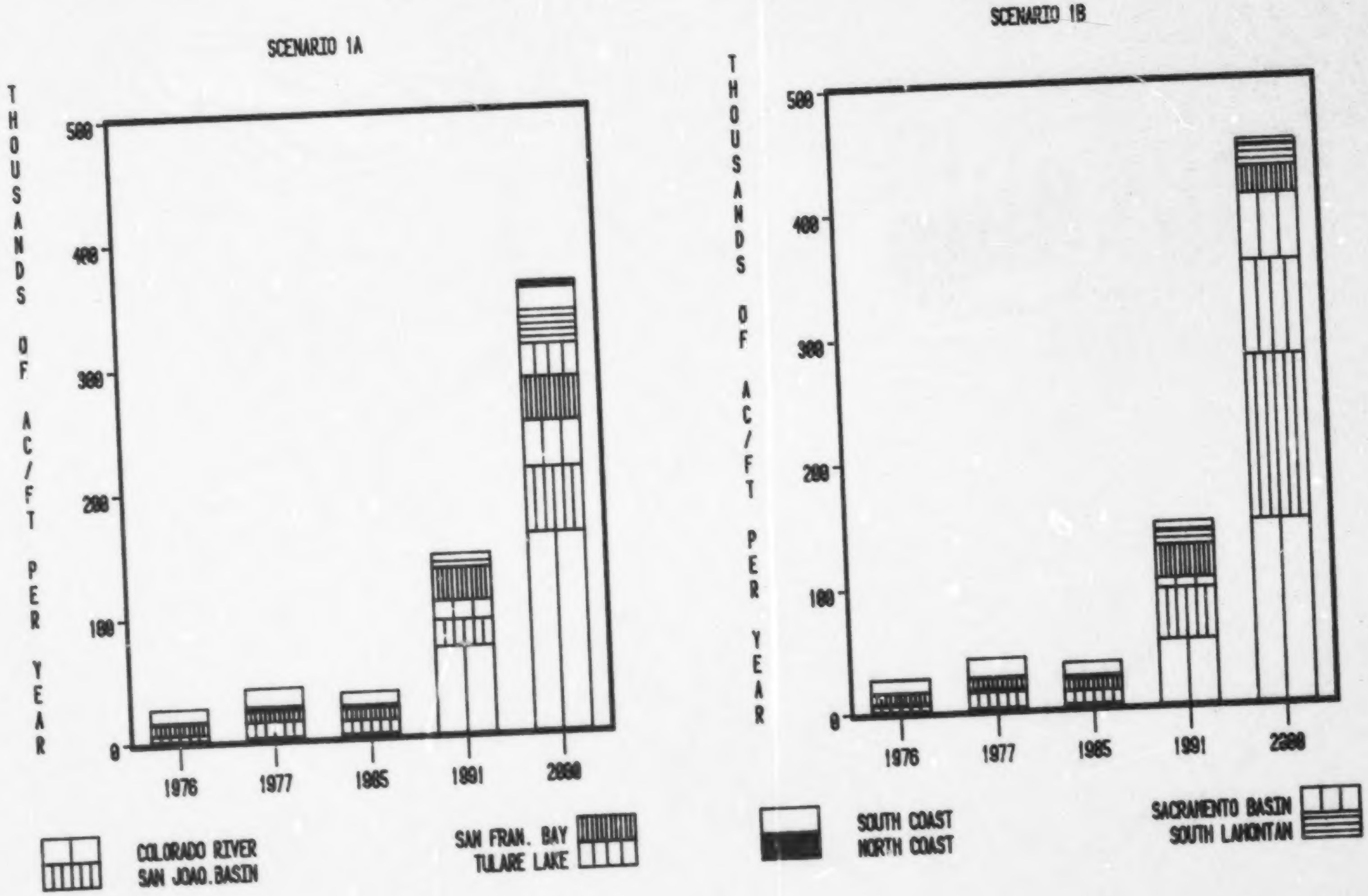
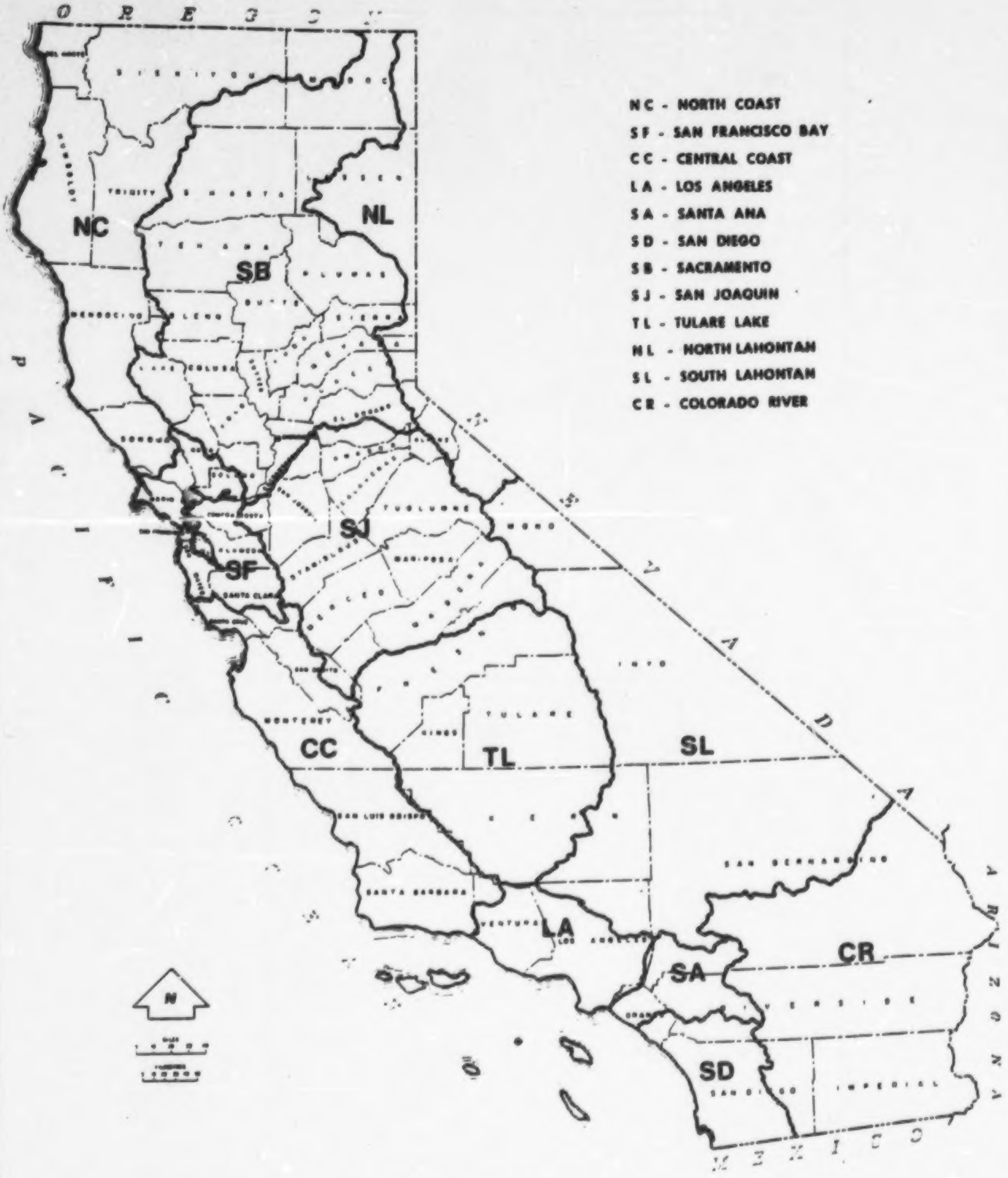


Figure 21


OREGON
NC - NORTH COAST
SF - SAN FRANCISCO BAY
CC - CENTRAL COAST
LA - LOS ANGELES
SA - SANTA ANA
SD - SAN DIEGO
SB - SACRAMENTO
SJ - SAN JOAQUIN
TL - TULARE LAKE
NL - NORTH LAHONTAN
SL - SOUTH LAHONTAN
CR - COLORADO RIVER
NC
NL
SB
SJ
SF
CC
TL
SL
LA
SA
CR
SD
N
PACIFIC OCEAN
NEVADA
ARIZONA
MEXICO

HYDROLOGIC BASINS OF CALIFORNIA

Source: California Department
of Water Resources

AUG 1979

the utilities' planned generation cold result in a nine-fold increase (to 360,000 AFY) in cooling water requirements if coal plants are emphasized and an eleven-fold increase (to 450,000 AFY) if nuclear plants predominate.

Among the Hydrologic Study Areas, the Colorado Desert Area has the largest prospective demand--about 40 percent of the total--due in large part to expected geothermal development in the Imperial Valley. It should be noted that some variations from the HSA distribution shown in Figure 20 are possible, since many anticipated plants have candidate sites in more than one HSA.

In addition to the in-state cooling water requirements, cooling water will also be required for new generating facilities located outside the state which supply electricity to California. Cooling water requirements for out-of-state generating capacity serving California is expected to increase about three-fold (to about 80,000 AFY), representing about 20 percent of the cooling water needed for all generation supplying the state.

The cooling water requirement calculations are based on six "cycles of concentration," meaning that cooling system waste water (blowdown) contains six times the concentration of impurities in the make-up water supply and accounts for one-fifth of the cooling water supply requirements.[18] The remaining four-fifths of the water supply requirements represent actual consumptive water loss through cooling tower evaporation.

Water use for noncooling purposes will add only slightly to the requirements for cooling. All power plants apply water to a number of uses, such as boiler make-up, equipment cleaning, sanitation, and groundskeeping, but the total of these uses will not usually exceed 1 or 2 percent of cooling tower make-up water needs. Other water uses are specific to certain plant types. For example, coal-fired power plants will require water for SO_2 scrubbers and ash handling systems. If a cooling supply of adequate quality is used, these needs can be filled with cooling system blowdown.[19]

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[18] Blowdown disposal considerations are discussed in the section on water quality.

Significance for Statewide Water Supply and Demand. Since the trend toward inland siting first became apparent in the early 1970s, the state's agricultural interests have voiced concern over possible competition from power plant projects for irrigation water supplies. Projected shortfalls in dependable water supplies for meeting increasing statewide water demands are usually cited as evidence that dependence on inland fresh water sources for power plant cooling water should be avoided. Indeed, the California Department of Water Resources (DWR) projects that, by the year 2000, net statewide water demands could exceed dependable supplies by as much as 6.6 million acre-feet per year (MAFY).[20] It should be noted, however, that DWR also provided a scheme to supply this short-fall, or "supplemental water demand", from new state and federal water development (2.3 MAFY); water conservation (1.8 MAFY); waste water reclamation (0.6 MAFY); and continuing groundwater overdraft (1.9 MAFY, reduced from the present 2.3 MAFY).

Figure 22 illustrates the DWR statewide water supply/demand projection for the year 2000; the CEC estimate of power plant cooling requirements for this year is shown as a part of the municipal/industrial sector. On the demand side, power plant cooling would require about 6 or 7 percent of the municipal and industrial (urban) water demand or about 1 percent of total fresh water demand for all sectors. Of course, the power plant demand will not be uniformly distributed;

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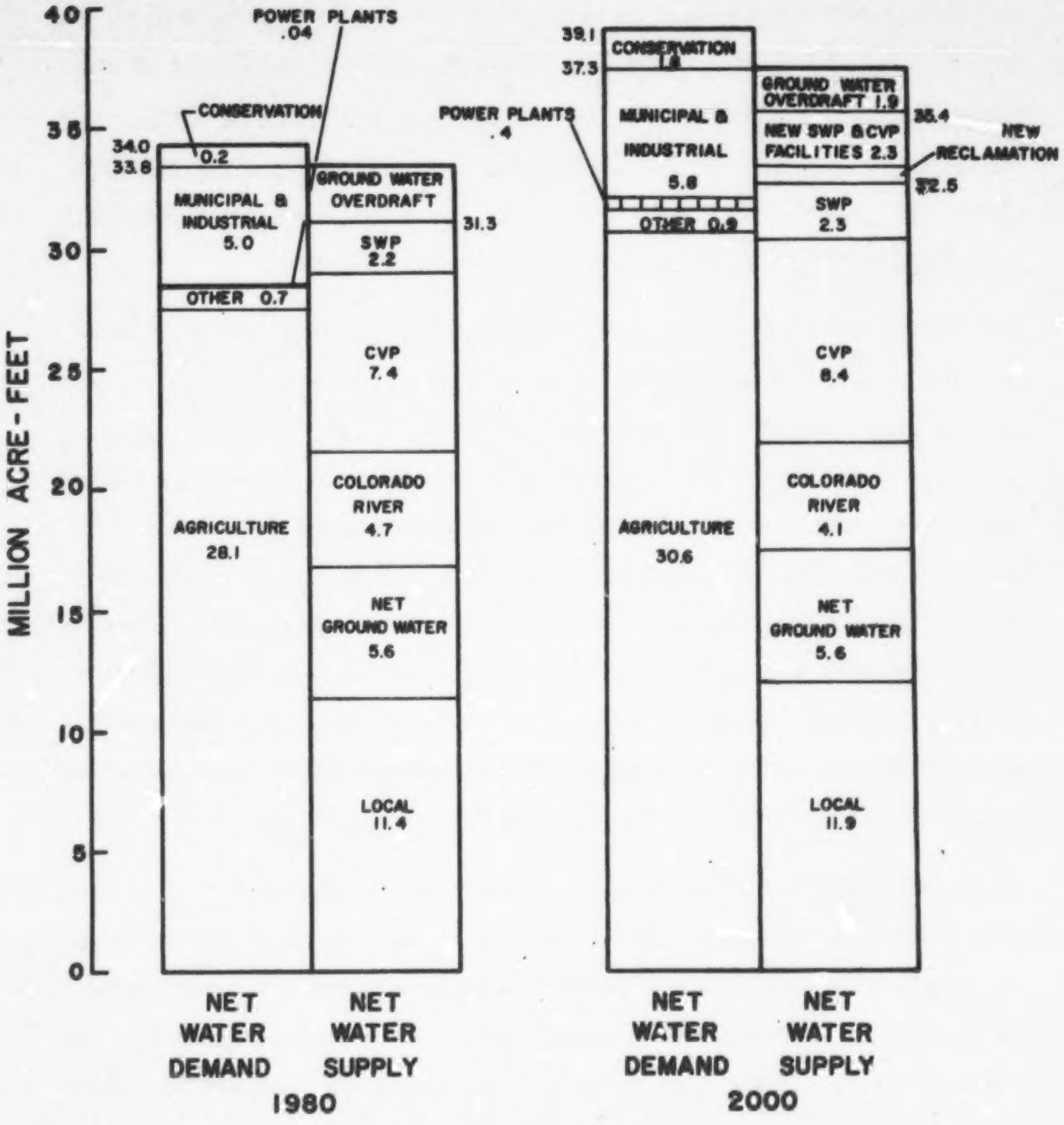
19. Environmental Control Technologies for a Northern California Coal-Fired Power Plant, Acurex Corp. (for CEC), June 1979.

20. Report of Activities of the Department of Water Resources. R. Robie, Director, February 2, 1979.

Figure 22

STATEWIDE WATER REQUIREMENTS AND SUPPLIES



Source: Ref 20 (pg 62)

certain areas of the state will experience a larger fraction of total water demand attributable to the power plant sector.

Despite its relatively small prospective share of statewide water demand, power plant cooling causes concern because of the magnitude of the projected increase in inland water use for this purpose. The steam-electric component of the present California electric generation system is still heavily reliant on ocean water for cooling (Table 5). Implementation of the utilities' plans, which emphasize new steam-electric facilities and inland sites, would make power plants the fastest growing water-using sector in the state, even though their total contribution to statewide water demand would remain small.

Furthermore, individual power plants are conspicuously large users of water. Even though cooling towers result in minimal effects on water quality if good quality make-up water is used (see discussion in water quality section), the losses associated with evaporation tend to arouse the objections of other water users. When compared with the domestic water supply, agricultural irrigation, or even other industrial water uses, some look upon power plant evaporative cooling as a less essential (or even inappropriate) use of water. There is also concern that power plant projects have the financial capability to "outbid" virtually any other water user for a given water supply. Thus, the arguments against fresh water use by power plants often appear to be based on socio-economic rather than true environmental considerations.

The potential for actual environmental effects due to the utilities' planned water use depends largely on the cooling methods used and water sources selected. Where fresh water is used, stream flow could be reduced; but most projects are expected to contract with a water supplier for a portion of an already-developed supply, rather than seeking a new allocation from natural stream flow. Where alternative, low-quality cooling water sources are used, the existing water supply may benefit only at the expense of environmental disadvantages such as cooling tower aerosol emissions,[21] blowdown disposal problems,[22] and increased energy use.

The Political and Regulatory Climate. Several government agencies and private organizations have responded to the prospect of large water demands from power plants by adopting policies to discourage utilities from securing water supplies from fresh water sources. Foremost among these policies is that of the State Water Resources Control Board (SWRCB). The State Department of Water Resources (DWR) and Food and Agriculture, as well as the California Farm Bureau Federation and the Association of California Water Agencies, have also adopted such policies.

Despite the present restraints on coastal siting and thermal discharge, these policies favor the use of ocean water to avoid power plant demands on inland water resources. The SWRCB suggests that the ocean is less susceptible than inland water environments to impacts from power plant cooling. The major thrust of SWRCB's policy is that power plant cooling water should be supplied from the following sources, in descending order of preferability: "waste water being discharged to the ocean, the ocean (itself), brackish water from natural sources or irrigation return flow, inland waste waters of low total disolved solids (TDS), and other waters."[23]

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[21] See discussion in air quality section.

[22] See discussion in water quality section.

[23] Water Quality Control Policy on the Use Disposal of Inland Waters Used for Power Plant Cooling. California State Water Resources Control Board, June 1975.

For the most part, these policies lack direct mechanisms for enforcement except in a rare case where a power plant project sought a water rights permit from SWRCB for a new allocation from waters of the state. In practice, SWRCB and other organizations apply their power plant cooling policies by intervening in proceedings of the CEC. As the state's power plant siting authority, the CEC has the most direct responsibility for deciding the acceptability of proposed power plant cooling methods. Planned projects which potentially add to fresh water demand can expect to meet opposition to their water-use components and to be required to investigate alternatives to evaporative cooling with fresh water.

The Options. To date, the options discussed and promoted as possible solutions to the problem of power plants competing for fresh water generally fall in two categories: cooling technologies that reduce or eliminate evaporative water loss, and low-quality sources of cooling tower make-up water that are unusable (or less desired) by other sectors. There have been individual investigations of each of the major options in these two categories; the results comprise a separate series of CEC reports which are nearing completion.[24]

Since the present utility plans are heavily oriented toward inland sites, the cooling options expected to be pursued will, for the most part, be low-quality water sources. Consideration of any such alternative water sources should try to weigh the intended water supply benefit against the environmental, economic, and energy disadvantages of employing the low-quality source in question. Wet/dry cooling towers, which could reduce cooling water requirements by as much as 80 percent, also merit continued evaluation, but present serious questions as to their economic and energy cost-effectiveness.

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[24] These investigations include: wet/dry cooling towers, setback coastal siting, inland once-through cooling, agricultural waste water, municipal waste water, brackish groundwater, and saline inland lakes.

Regional Implications. The candidate sites for planned steam-electric facilities reflect the importance of water supply as a siting factor (Figs. 1, 2, and 3). However, the ability to take advantage of water supply opportunities is often limited by other siting considerations; the almost total avoidance of new coastal facilities is the most notable example.

Inland site selection must face various problems in attempting to simultaneously accomodate water supply objectives and other siting requirements. This type of conflict is particularly evident in the utilities' planned fossil-fuel burning facilities where air quality considerations dominate the site-screening efforts.

As a result of site-screening studies, candidate sites for fossil-fueled power plants will often be remote from alternative water sources such as municipal waste water or agricultural drainage water. This is the case with sites identified for coal-fired projects planned by PG&E and SCE. The extensive statewide water supply network makes it possible to deliver fresh water to these locations, but obtaining a low-quality water supply would be extremely problematic and expensive. One option that may be feasible at some remote locations is groundwater, including some brackish groundwater basins with minimal competing uses.

Southern California liquid-dominated geothermal projects present another unique water supply dilemma. These projects, in locations fixed by the availability of the geothermal resource, could probably satisfy much or all of their cooling needs with geothermal fluid, as is done by Northern California (Geysers) geothermal plants. However, concern over possible land subsidence has led to a requirement by Imperial County that 100 percent reinjection of withdrawn fluids be practiced.[25] If maintained, this requirement will dictate the need for outside cooling water supplies (or replacement reinjection supplies) for these highly water-consumptive facilities.

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[25] Geothermal Element of the Imperial County General Plan, Adopted November 1977.

About three-fourths of the projected year 2000 cooling water requirements in the Colorado Desert Hydrologic Study Area are for geothermal projects; this also constitutes almost half of the increase in statewide cooling water requirements by 1991. Although planned developments have been granted initial supplies of fresh water from the region's irrigation supply system, this is for a temporary period (e.g., 5 years), and ultimate development of alternative sources is necessary. Agricultural drainage into the Salton Sea is the primary option under investigation, although the effect of such inflow diversion on the Sea remains controversial.

The effects of power plant cooling water supply on the outflow of the Sacramento-San Joaquin Delta is also a subject of continuing interest and controversy. As with any other prospective increase in applied water use, power plant cooling potentially diminishes the water supply necessary for maintaining a Delta outflow adequate for salinity control. This concern applies to virtually any power plant project in the state which plans to use fresh water, since any new water demands are viewed as adding impetus for further development of Northern California waters--expansion of the State Water Project and Federal Central Valley Project--which supply the Delta.

If the entire year 2000 statewide cooling water requirement of 360,000 to 450,000 AFY was considered in measuring the depletion of Delta flow it would only represent about 3 percent of the present total level of diversions from the Delta system.[26] However, it appears unlikely that a major portion of power plant water requirements will be supplied anyway which competes directly with Delta outflow.

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[26] California Water. Bulletin 201-77, California Department of Water Resources, February 1977.

Water Quality

Virtually all types of electric generating facilities have some potential for degrading water quality. The potential sources of water quality effects are: discharges of water from cooling systems, liquid effluents from other plant systems, diversions of water from water bodies for facility use, and disruptions of watersheds for facility construction.

As with their effects on water supply, the potential effects of power plants on water quality are largely related to the type of cooling and mode of cooling system operation employed. The predominance of steam-electric facilities using evaporative cooling towers at inland sites suggests that disposal of cooling tower blowdown would be the most important water quality consideration in implementing the utilities' plans.

The quantities of blowdown requiring disposal could vary widely (as indicated in Table 3) depending on the quality of the cooling water source, water treatment applied, and number of "cycles" (or concentrations) allowed; these will also determine the quality of the blowdown and the options for its disposal. Generally, if a freshwater source is used for cooling tower make-up, blowdown will be of sufficiently high quality to allow discharge into a surface watercourse; this is the case with several California power plants, with the blowdown effluent used for irrigation in some cases.

Where an alternative, poor-quality water supply, is used, cooling tower blowdown disposal will usually be more of a problem. If a sufficient supply volume is available, blowdown quality can be controlled with low cycles of concentration; however, this greatly increases the amount of blowdown. In any case, it should be remembered that the mass balance (total actual amount) of blowdown impurities will be the same, fixed by the amount of evaporative water loss. Except for relatively minor additions of cooling water treatment chemicals, the only change in the quality of cooling tower water is the concentration of impurities present which were in the make-up water initially.

If blowdown cannot be discharged into a surface watercourse, other disposal options may include:

- Use of evaporation basins with impermeable liners and other protective measures to prevent basin contents from reaching surface or ground waters;
- Return to the supply source, which could be a municipal sewer system or an agricultural drainage collection system, providing that acceptable water quality conditions in the source/receiving water can be maintained;
- Recycling for cooling system or other reuse; this is expected to be common practice for coal-fired plants, where blowdown can be used in scrubbers and ash handling systems; or
- Subsurface injection, which is applicable mainly to geothermal projects, where blowdown helps to maintain the balance of reinjected and withdrawn fluids.

With proper use of these disposal alternatives, as dictated by individual project circumstances, significant effects on water quality from blowdown disposal should be largely avoidable. It should be remembered, however, that the increased potential for impacts on water quality represents an environmental disadvantage when poor-quality cooling water sources are employed to mitigate the effect on water supply.

Coastal facilities have a fundamentally different set of potential effects on cooling-related water quality. Here, the waste water effluent is the entire condenser cooling water flow (about 1 cubic foot/second per megawatt of steam plant capacity) heated from 15° to 30°F above its initial temperature and sometimes containing chlorine or other chemical additives. Long-standing debate has centered around the types and extent of environmental impacts of such thermal discharges; there has not been a consensus among scientists that there are significant adverse consequences to marine environments. Nevertheless, the U.S. Environmental Protection Agency's (EPA) position, which discourages once-through cooling in favor of cooling towers, continues to be a factor in the demise of coastal siting activity. A further consequence of--and argument against--once-through cooling is the mortality of marine organisms due to entrainment or impingement in the cooling system.

Even with the utilities' emphasis on inland siting, the use of ocean once-through cooling in California will increase by at least 23 percent, from 18,980 MW to 23,000 or more MW, using this method. Therefore, impacts on the marine environment will continue to be a major consideration in the state's electricity supply. The establishment of federal requirements for cooling towers at coastal facilities (even the retrofit of existing plants) remains a possibility, although improved technologies for once-through cooling intakes and discharges are the measures receiving the most current attention to resolve this problem.

In addition to cooling system waste water, most power plants have other types of impacts on water quality due to various routine or inadvertant operating circumstances. Fossil-fuel plants must dispose of cleaning wastes, often containing acids and metals; discharge of these wastes into a body of water is permitted only after extensive treatment to reduce levels of objectionable constituents. Both nuclear and fossil-fueled steam plants produce steam boiler blowdown, a waste water stream which usually poses a very slight disposal problem due to its relatively high quality and small volume. Virtually any type of generating facility will produce sanitary waste water, but again, this represents only a minor disposal problem. Other potential effects on water quality are unique to certain generation types. These include

- Routine and accidental release of radionuclides in the liquid effluents of nuclear plants;
- Leaching or runoff of constituents of ashes and sludges from coal plants, and runoff from coal storage;
- Spillage or leakage of fuel oil from oil-burning plants; and
- Contamination of surface or groundwater with fluids from geothermal plants; erosion caused by site development is a particular problem for geothermal projects in the steep terrain of Lake and Sonoma Counties.

With the application of modern waste water treatment systems and other controls, together with effective operating practices and diligent personnel, the routine operation of most generating facilities will have minimal adverse effects on water quality. In fact, power plants may deserve to be viewed as relatively "clean" operations, if compared to the industrial sector as a whole. Nevertheless, the possibility of pollution by generating facilities must be acknowledged, and appropriate levels of controls and enforcement maintained.

V. LAND USE

New facilities planned by the major California utilities will need sites in various regions of the state. New transmission lines will require additional land. The amount of land needed for expanding electric generation and transmission facilities appears small when compared to overall urban and rural development in the state. However, the effects--real or perceived--on surrounding land uses due to the operation and appearance of such facilities are complex and controversial issues.

Generating Facility Land Requirements

Land requirements vary considerably with different types of electric generating facilities. Representative requirements for nominal size facilities of the types contained in the utilities' plans are compared in Table 6.

Of the major generating methods proposed coal-fueled plants are the most space-consuming. They occupy about 20 times more acres per megawatt than oil- and natural gas-fueled facilities. Most of the space required for a coal plant is the storage area for solid waste accumulated throughout the life of the plant (see discussion in solid waste section); this area is roughly equal to that needed for all other components of the plant combined. In contrast to other types of plants, coal plants also need large areas for coal storage, as well as rail sidings and unloading facilities for coal trains.

Under NRC regulations, nuclear plants require exclusion areas which must extend one-quarter mile in every direction; these areas typically cover about 500 acres. This area must be secure at all times; a factor that tends to exclude most land uses except limited agriculture. Also, a low population zone must be maintained at some distance beyond the exclusion area.

TABLE 6

LAND REQUIREMENTS FOR DIFFERENT GENERATION TYPES[1]

Generation Type	Requirement (acres)
Coal	1700 A/500 MW
Nuclear	2100 A/1300 MW
Combined Cycle	40-125 A/500 MW
Cogeneration (enhanced oil recovery)	35 A/280 MW
Geothermal	35-70 A/110 MW
Wind	50 A/50 MW
Fuel Cells	2 A/5 MW
Hydro-electric (includes pumped storage)	100 A(3000 A w/impoundment)/ 150 MW
Solar Thermal Electric	700 A/100 MW

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[1] Included in these figures are space requirements for generating plant structures, as well as ancillary facilities such as cooling towers (where needed), fuel storage and handling systems, and waste storage or disposal areas. Evaporation basins for cooling tower blowdown disposal, although a potential large additional land requirement, are not considered since the need for and size of such facilities is less a function of generation type than of the type of cooling water used. Figures were derived from various sources as part of ongoing staff "Generic Technology Assessment" project.

Geothermal plants require interconnected pipeline networks, along with production- and reinjection-well pads, access roads, and turbine-generator buildings. While the total land occupied by a single project may not be extensive, multiple projects in a single geothermal resource area affect the entire area of development.

For cogeneration projects, the electrical generating equipment must be located adjacent to the integrated industrial process. Therefore, cogeneration plants will always be sited on or adjacent to existing industrial land, minimizing the effect on land use. Fuel cells offer the advantage of being sited at substations or other existing facilities, and require minimal new site development.

The repowering of existing facilities probably requires the least additional land since most, if not all, modifications take place within the existing plant boundaries.

Solar thermal-electric generation appears to be the most land-use intensive technology yet considered due the large collector surfaces required. (Hydroelectric projects would require more land if the reservoir is included.)

New transmission line corridors require rights-of-way up to several hundred feet wide; these usually traverse many miles of land which has various uses. However, only a fraction of this land is actually occupied by support towers and access roads, and most of it remains usable for other purposes.

Land Use for the Utilities' Plans

The total land required for new in-state generating facilities planned for the next 20 years ranges from 60,000 to 100,000 acres for the nuclear and coal scenarios, respectively. For perspective, total urban land use in California (including industrial, commercial, and residential development) currently occupies about 2.5 million of the state's 100 million acres of land area and is to be increasing at a rate of up to 50,000 acres per year.[27] Thus, the use of the land for new electric generation facilities could be equal to as much as 10 percent of the rate of urban land development in the state.

This acreage requirement belies the extent to which potential land use impacts are of concern and controversy in implementing the plans. Some concerns raised in the name of land use are actually extensions of other environmental issues, such as air quality or water supply. Land use controls, in the form of zoning, building permits, provision of public services, etc., can provide local jurisdictions with mechanisms for affecting virtually any aspect of a project proposal.

Separating a land-use controversy from other issues related to project development can be difficult. Recent public referendums demonstrating local opposition to the construction of two different power plants exemplify this phenomenon. In both cases, voters opposed the choice of the site in question as an appropriate location for the project because of concerns including water supply, air quality, and plant safety. Therefore, consideration must be given not only to the high land consumption of Scenario 2, but the extent to which potential land use impacts represent subject of concern and controversy for implementation of the scenario.

By 1991, the utilities plan to install up to 700 miles of new high voltage transmission line routes in the state to transmit power to urban load centers from new generation projects and out-of-state sources. Additional lines could be needed by 2000. Acquiring the rights-of-way for these transmission lines is likely to add significantly to the land required for generating facilities.

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[27] Land Use in California. Bulletin 176, California Department of Water Resources, December 1971.

As with candidate sites for new generating facilities, local controversy and opposition often focus on the routes of proposed transmission lines due to their visual impact on the landscape, as well as their potential public health and safety impacts, and biological effects such as increasing bird mortality.

Regional Issues

Most land-use issues likely to be confronted during implementation of the utilities resource plans have specific regional orientations.

Coastal vs. Inland Siting. The utilities' de-emphasis of new coastal sites appears to have effectively minimized potential conflicts with the coastal land use designations of the California Coastal Commission. Two projects in the coastal zone, SCE's San Onofre and PG&E's Diablo Canyon Nuclear Plants, are nearing completion. Other projects planned for the coastal zone include PG&E's Potrero and Pittsburg Combined Cycle Plants (and possibly repowering of the Contra Costa Plant), and SCE's Combined Cycle and California Coal Plants, for which Huntington Beach and Ormond Beach are named along with many inland candidate sites. Since all of these prospective coastal projects would rely on expanding of existing power plant sites, coastal land-use restrictions are not expected to be a major problem. Nevertheless, debate over the relative preferability and advantages of coastal versus inland power-plant siting will continue to surround these projects.

Opposition by agricultural interests to power plant use of inland water supplies insures that the coastal versus inland controversy will continue to surface in discussions of inland projects. Renewal of interest in coastal siting would be more likely in a heavily coal-dominated case than a nuclear case, due to the seismic potential along the coast.

Urban vs. Rural Siting. Another characteristic of the utilities' electricity supply plans which stimulates controversy is a trend toward locating generating facilities in areas which do not have major power plant or industrial projects. Coal-burning power plant projects planned by PG&E for Northern California and by SCE for Southern California have candidate locations which are subject to such concern. Although the potential for actually displacing agricultural or other rural land uses appears small, the prospect of a major power plant in an area previously unaffected by such development can foster substantial opposition. In addition to the general incompatibility with other land uses, increased transmission length needed for more remote sites results in greater land requirements and energy losses. However, the difficulties involved in overcoming community opposition and environmental restrictions at urban sites are often more severe obstacles.

Even expanding an existing power plant located in the midst of urban development faces public resistance and problems with regulatory compliance. The repowering of steam turbine plants (conversion to combined cycle) is one option for substantially increasing generation capacity and improving plant efficiency without developing new sites, but this figures minimally in the utilities' current plans.

Other nonconventional technologies--such as cogeneration and fuel cells--which will be located at industrial sites, substations, and other existing developments, cumulatively contribute an amount of capacity to the plans equivalent to that of two or three large (1000 MW) projects.

In-State vs. Out-of-State Siting. Reliance on out-of-state power plant projects will increase substantially during the next 20 years to more than triple the out-of-state ownership of generation capacity. Although this reduces the need for new in-state facilities by roughly five new 1000 MW projects, it poses concerns related to regional equity and the "export of impacts" from electric generation. In short, if generating plants which primarily serve the urban areas of California face public resistance at potential rural sites within the state, even greater opposition to their presence can be expected in other states. This opposition can be minimized by engaging in joint-ownership ventures with utilities in these states (Nevada, Arizona, and Utah). Another disadvantage of such projects from the standpoint of California's electricity supply, is their dependence on permits and regulatory compliance in non-California jurisdictions.

Geothermal Development. The planned expansion of Northern California (Geysers KGRA), geothermal power generation and the introduction of brine geothermal generation to the Imperial Valley of Southern California face land-use issues specific to this technology. Utilizing geothermal potential involves the construction and operation of multiple power plant projects within the physical extent of the known resource; there is little flexibility in choosing sites. The result is a cumulative level of development that is virtually certain to conflict with other land uses.

Continued development in The Geysers area will contribute to aesthetic (visual, noise, and odor) impacts, soil erosion, and biological habitat disruption; these, along with hydrogen sulfide emissions, are problems with existing facilities. Since plant sites in the Imperial Valley will often be on or adjacent to agricultural land, the direct displacement of a limited amount of agricultural activity is a possibility. The potential for land subsidence due to the withdrawal of geothermal fluid is an even more serious concern and the subject of continuing investigation.

Federal Wilderness Area Designations. The U.S. Bureau of Land Management (BLM), is the implementing authority for the Federal Land Policy and Management Act of 1976 (P.L. 94-579); it recommends land areas for designation by Congress as permanent wilderness areas. In California, much of the attention on this program has focused on the Southeast Desert Area, which is also a prospective siting area for major new generating facilities. Thus far, BLM has selected 5.5 million acres (about one-fifth of the southeast quarter of the state) as wilderness study areas, meaning that these areas are closed to energy facility (and other) development, at least for several years during which permanent determination of their status is pending. An even larger portion of this region is occupied by parks, national monuments, and military reservations which, of course, are also off limits to power plant projects.

Transmission Line Routes. As with choices between alternative sites for generating facilities, selection of new transmission line corridors often stimulates intense regional controversy and debate. The most notable cases with respect to the utilities' current plans involve selecting routes for transmitting power generated by Imperial Valley geothermal plants and by new out-of-state sources to the metropolitan load centers. Many corridors have been proposed, some of which traverse agricultural areas. Routes ultimately chosen as "preferable" (least objectionable) may be those which parallel corridors of existing developments such as highways or aqueducts.

VI. NUCLEAR WASTES

The normal operation and decommissioning of the nuclear electric generating plants included in the utilities' plans will produce radioactive waste by-products. Although there are no clear definitions, the waste products can be loosely grouped into two categories depending on the longevity and nature of their radioactivity: low-level and high-level radioactive wastes.

Low-level wastes from normal operations result primarily from systems within the plant designed to purify various radioactively-contaminated liquid and gaseous streams. These wastes include filters, demineralizer resins, and everyday waste, such as rags and paper that have been contaminated. High-level radioactive waste from normal operation is defined here as the spent fuel assemblies, one-third of which must be replaced annually as they become contaminated with fission products which inhibit the nuclear chain reaction (fission). Following the useful life of a reactor--generally 30 to 40 years--steps must be taken to remove and isolate contaminated structural materials. These activities produce decommissioning wastes which include contaminated cleaning solutions, equipment, and reactor components. The amount and types of decommissioning waste depends on the decommissioning method used; however, it is assumed here that dismantling and decontamination will be utilized.

The radioactive wastes from nuclear power reactors must be carefully managed, because as long as they remain radioactive (up to hundreds of thousands of years, depending on the isotope) they are a potential hazard, and must be isolated from the human environment as long as they remain hazardous.

Low-level wastes are buried at licensed commercial burial sites, while decommissioning wastes will go to either landfill areas, if nonradioactive, or licensed burial sites (radioactive). High-level wastes are currently stored at the reactor sites; eventually they must be disposed of elsewhere, probably deep in stable geologic repositories.

A major concern is that there are no comprehensive criteria or standards defining acceptable sites for either high- and low-level disposal methods. Therefore, the adequacy of current and proposed disposal methods is inevitably challenged. Until acceptable disposal methods are established, a real danger exists in producing additional wastes which will exhaust the capacities of current burial or storage sites.

Low-Level Waste

The amount of low-level waste produced at a nuclear plant depends on the type of reactor--pressurized water or boiling water reactor (PWR or BWR)--types of cleanup and volume reduction systems, operating procedures, and the age of the plant. Data from operating plants indicate that the amount of waste increases with plant age until an "equilibrium value" is reached.

For PWR plants, the equilibrium value is approached after 4 to 8 years and is about 17 to 30 cubic feet per megawatt of installed capacity per year.[28] For BWR plants, the equilibrium value is typically 40 to 50 ft^3 per megawatt and is reached after 5 to 12 years of operation. Although quantities produced can vary widely due to shutdowns or other occurrences, usually the amounts of waste produced have been greater than predicted at the design stage. The estimated volumes of low-level wastes shipped from California nuclear plants are shown in Figure 23; California's share of waste produced in out-of-state plants is included.

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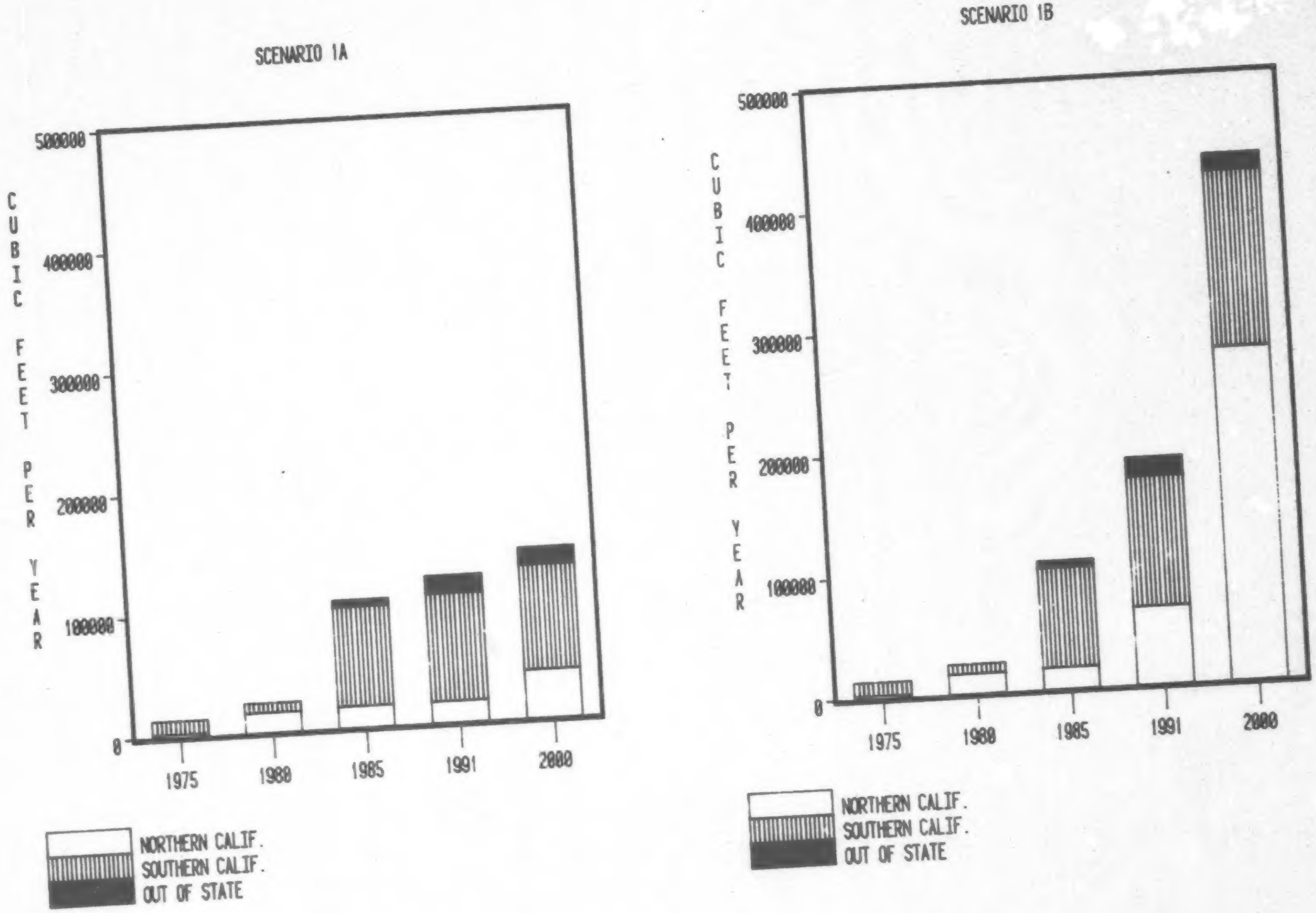
28. *Power Reactor Low-Level Radioactive Waste Generation and Waste Management Practices Evaluation Report E, Policy Recommendations, Conclusions and Summary*. NUS Corp., April 1979.

Figure 23

QUANTITIES OF LOW LEVEL RADIOACTIVE WASTE GENERATED PER YEAR



Typically, low-level wastes are placed in 55 gallon drums and wooden boxes for transportation and disposal. Once the waste is packaged, it is stored on-site until shipped (usually by truck) to a licensed burial facility. Of the six commercial sites in the United States, two are in the west at Beatty, Nevada and Hanford, Washington. Currently, neither the NRC nor the states in which the burial sites are located have comprehensive licensing criteria. The EPA is developing general environmental criteria for low-level waste management activities and a specific standard for shallow land burial is to be issued by 1983. Inadequate disposal methods could allow radionuclides to escape into the environment, primarily through groundwater; the resulting hazard would depend on the specific pathways taken by the escaped nuclides.

Currently, only one eastern site is open. Recently, both western sites have been ordered closed for various periods by the governors of Nevada and Washington, each charging gross deficiencies in the disposal operations in their states. The problem of disposing of low-level radioactive wastes is not unique to the electric utility industry. In fact, power plants probably produce only one-fourth of the current low-level waste in California.

High-Level Waste

During the operation of a reactor, the fuel becomes contaminated with fission products and must be replaced. Typically, about one-third of all the fuel rods in a reactor's core are removed each year. This spent fuel is then stored on-site in water-filled pools to allow the heat and radiation to dissipate. Originally, spent fuel was to remain on-site for only six months and then be transferred to a reprocessing plant where unfissioned fuel could be extracted and reused. However, commercial reprocessing never became a reality, and spent fuel rods remain stored in on-site pools at each reactor. Since long-term on-site storage was not envisioned, the pools were originally designed to hold only one discharge (1/3 core) plus a full core reserve in case of an emergency; the full core reserve capacity was not a design requirement, however. Although some spent fuel pools can be expanded or modified to provide more on-site storage, continued storage at the plant sites is a significant variation from original project plans and suggest a need for further, serious evaluation of this practice.

The estimated amounts of spent fuel discharged under the nuclear and coal scenarios are shown in Figure 24. All existing or under-construction reactors of the California utilities will lose full core unloading capability before 1990 (Table 7). Eventually, the spent fuel must be disposed of permanently, or if reprocessing is to take place, be shipped to a reprocessing plant. In either case, the high-level waste must be effectively isolated from the human environment until it is no longer deemed hazardous. Estimates of this required isolation period vary, but 250,000 years is frequently mentioned.[29] The capability of current technology to provide such isolation with a high degree of confidence has been seriously questioned.

In 1976, the California Legislature enacted AB 2822 (California Public Resources Code Section 2524.2) which prohibits certification of any nuclear power plants in California until the CEC determines that a demonstrated technology for the permanent, terminal disposal of high level nuclear waste exists and has been approved by the appropriate federal agency. In 1978, the Commission found that the technology exist to adequately dispose of high-level waste did not yet exist; it has not since changed its finding. Construction of new nuclear power plants in California is prohibited by law at the present time.

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[29] Report to the American Physical Society by the study group on nuclear fuel cycles and waste management in Reviews of Modern Physics, January 1978.

Figure 24

QUANTITIES OF HIGH-LEVEL RADIOACTIVE WASTE GENERATED PER YEAR

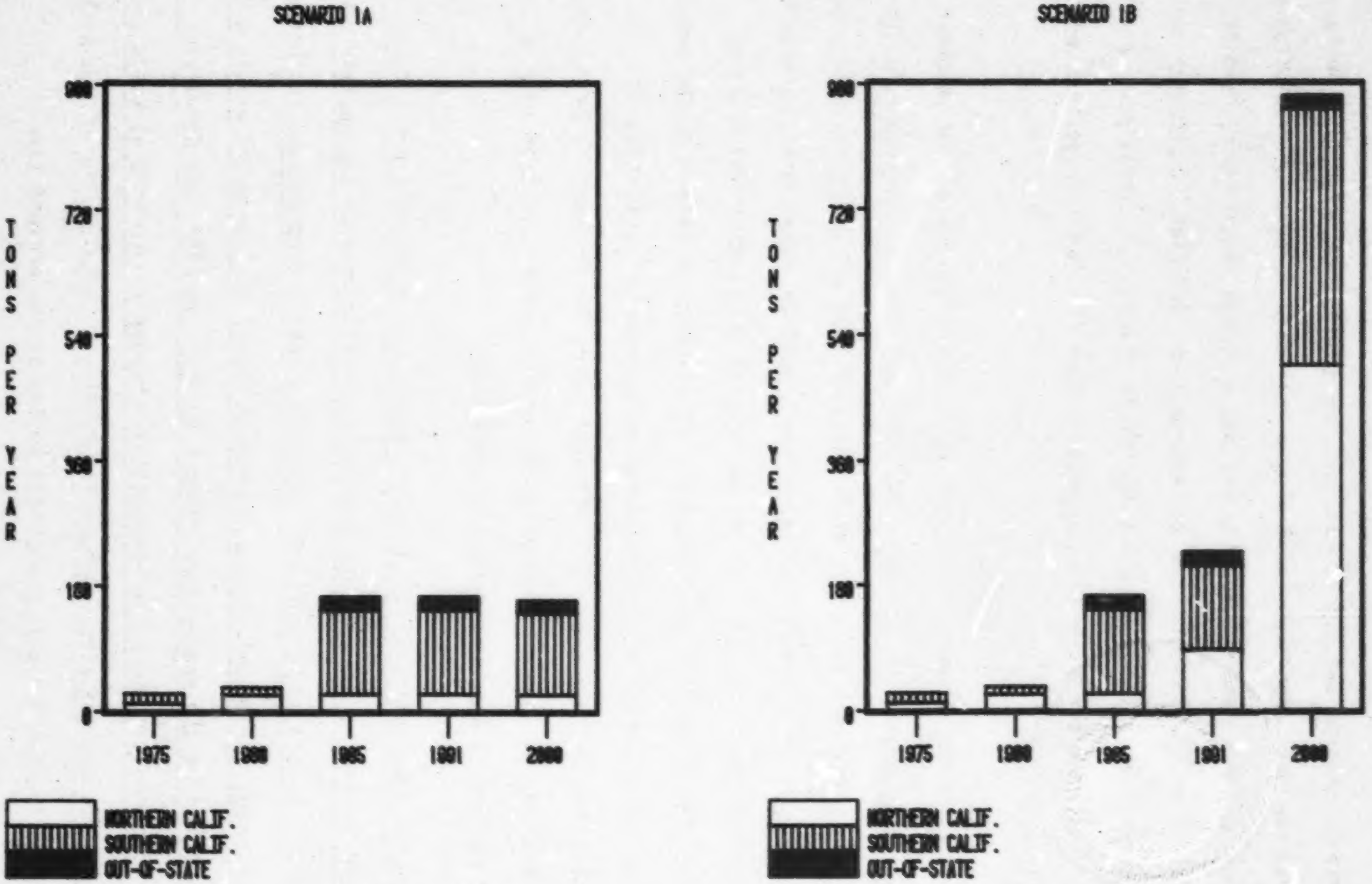

TABLE 7

ESTIMATED DATES WHEN ON-SITE SPENT FUEL STORAGE OF CURRENT NUCLEAR PLANTS WILL APPROACH CAPACITY

Facility	Operating Status	Loss of Full Core Discharge Capability*
Humboldt Bay	Indefinite Shutdown	1983
San Onofre 1	Operating	December 1982
San Onofre 2	Advanced Construction	December 1988
San Onofre 3	Advanced Construction	December 1989
Rancho Seco	Operating	Fall 1984
Diablo Canyon 1	Licensing Pending	About 1988
Diablo Canyon 2	Licensing Pending	About 1989

*Source: CEC Hearings on Nuclear Fuel Reprocessing and Waste Management, March 10, 1977: assumes no expansion of installed storage capacity and plant operations as scheduled.

The nuclear generation component of the utilities' plans through 1991 consists of either facilities already in operation or in advanced stages of construction or licensing, plus one new out-of-state project. To implement the remaining years of the high nuclear case (Scenario IB) the high-level waste disposal problem would have to be resolved soon enough to allow adequate lead time for the nuclear projects in this scenario.

Although the federal program to develop a high-level waste disposal method consists of a number of activities and has identified many research needs, it is not exptected that a disposal method will be demonstrated before the late 1980's, at the earliest. Until then, spent fuel will continue to accumulate in the reactor's spent-fuel pools. This poses the problem for both existing and new nuclear plants of possible running out of spent fuel storage capacity and having to locate additional storage, possibly off-site. If sufficient capacity is not available, the plants face the possibility of having to shut down.

Decommissioning Waste

At the end of a nuclear plant's useful life, it must be decommissioned. It is assumed that this will be accomplished by decontaminating and dismantling the structure. To date, no large, modern power reactor has evern be decommissned. None of the California utilities' nuclear projects are planned for decommissioning during the study period, but the status of PG&E's Humboldt Bay Plant, the state's first commercial reactor, is somewhat uncertain. However, the quantities of waste which are expected ultimately, and which represent "deferred" waste disposal implications for the utilities' plans have been estimated. One estimate indicates that typical quantities of waster from removal and dismantling operations requiring burial at a licensed facility would be 351,000 cubic feet for a pressurized water reactor (all California plants except Humboldt are PWRS), and 837,000 cubic feet for a boiling water reactor.[30] Another study estimated that the decommissioning of San Onofre 1 would result in 182,000 cubic feet of waste.[31] Based on these figures, the decommissioning of existing or under-construction reactors in California and California's share of those out-of-state would result in approximately 2.6 million cubic feet of waste requiring burial at licensed facilities. Thus, the volumes of wastes resulting from decommissioning nuclear reactors could approximately equal the amount of low-level wastes produced over a period of ten years.

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[30] An Engineering Evaluation of Nuclear Power Reactor Decommissioning Alternatives. Atomic Industrial Forum National Environmental Studies Project, November 1976.

[31] San Onofre Nuclear Generating Station Decommissioning Alternatives, pp. 72-74. NUS Corp., February 1977.

VII. COAL PLANT ASH AND SLUDGE

Coal-fired power plants planned by California utilities will generate large volumes of solid waste. These wastes will include sludge from flue gas desulfurization (FGD) systems, fly ash from the stack-gas particulate removal device, and noncombustible coal residue (bottom ash) from the boiler. Among the constituents of these waste products are many potential pollutants, including toxic trace elements and low-level radioactive elements, which must be effectively segregated from the environment, especially from usable surface and groundwaters. Therefore, coal-burning power plants must employ certain solid waste management techniques to avoid pollution and to comply with disposal laws and regulations.

Waste Products

Fly ash comprises the major portion (usually about 80 percent) of coal ash residue. It is the ash carried in the combustion gas leaving the boiler, and is subsequently captured by a particulate control device. In most planned California coal plants, fly ash will be removed with fabric filters (baghouses) designed to be more than 99.9 percent effective at collecting fly-ash particles. Most existing coal-fired plants, including SCE's Mojave plant in Nevada and the LADWP co-owned Navajo plant in Arizona, use electrostatic precipitators which are about 99 percent effective in controlling particulates.[32]

Bottom ash is the remaining ash residue which collects in the bottom of the boiler. In pulverized coal boilers such as planned for PG&E's Fossil 1 & 2 project) ash hoppers at the bottom of the boiler are used to collect the bottom ash.

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[32] Environmental Control Technologies for a Northern California Coal-Fired Power Plant Acurex Corporation, prepared for CEC, June 1979.

The major chemical composition of the bottom and fly ash fractions are similar, with common substances such as silica, iron, calcium and aluminum being the predominant components. The environmental significance of the ash is due to other elements which, although present in only trace concentrations (tenths of 1 percent or less), have toxic potential if assimilated by plant or animal life. Some of these elements may be many times more concentrated in the ash than in the coal itself. Trace element analyses of ash from coal PG&E plans to use in its Fossil 1 & 2 project show that relatively high concentrations of many exotic constituents can be expected (Table 8). There are also extreme variations in these concentrations among individual samples.

Nonregenerable, or "throwaway" flue gas desulfurization (FGD) systems, such as proposed for use by PG&E, produce spent sludge which contains high concentrations of sulfur compounds plus significant amounts of fly ash. While sludge production may be only half of ash production on a dry weight basis, the volume of wet sludge requiring disposal will usually exceed that of ash because of the sludge's liquid content.

Because of their constituents, both ash and sludge must be handled and disposed of in a manner that prevents their movement through the environment; it is most important that they do not contaminate surface water environments or leach (infiltration of subsurface drainage containing soluble substances) into groundwater. A second environmental concern is the large land areas required for landfill disposal sites.

Waste Production

The weight and volume of ash and scrubber sludge from operating the coal-fired power plants in each of the two variations of the utilities' plans has been

TABLE 8

TRACE ELEMENTS IN ASH FROM SAGE POINT COAL[1)]

(PPM by Weight)

	High	Low	Avg.		High	Low	Avg
Antimony	27.0	0.7	13.85	Manganese	1300.0	31.0	665.5
Arsenic	24.0	2.0	13.0	Mercury	0.13	0.01	0.07
Barium	5600.0	5.0	2800.0	Molybdenum	39.0	1.0	20.0
Beryllium	5.0	0.9	2.95	Neodymium	39.0	2.0	20.5
Bismuth	9.6	0.3	4.5	Nickel	80.0	20.0	50.0
Boron	2600.0	34.0	1317.0	Niobium	67.0	3.0	35.0
Bromine	8.0	0.2	4.1	Osmium	3.0	0	1.5
Cadmium	2.0	0.2	1.1	Praseodymium	230.0	2.0	116.0
Cerium	00.0	16.0	358.0	Phenium	6.0	0	3.0
Cesium	19.0	0.1	9.55	Rubidium	390.0	20.0	205.0
Chromium	300.0	96.0	198.0	Samarium	27.0	1.0	14.0
Cobalt	110.0	7.0	58.5	Scandium	110.0	16.0	63.0
Copper	430.0	24.0	227.0	Selenium	5.0	0.4	2.7
Dysprosium	5.0	0.9	2.95	Silver	5.0	0.1	2.55
Erbium	2.0	0.1	1.05	Strontium	6200.0	450.0	3325.0
Europium	5.0	0.4	2.7	Tantalum	26.0	0.1	13.5
Fluorine	1200.0	110.0	655.0	Tellurium	3.0	0.1	1.55
Gadolinium	5.0	0.4	2.7	Terbium	3.0	0.6	1.8
Gallium	60.0	7.0	33.5	Thallium	2.0	0.4	1.2
Germanium	4.0	0.8	2.4	Thorium	45.0	8.0	26.5
Gold	3.0	0	1.5	Thulium	1.0	0.1	0.55
Hafnium	5.0	0.1	2.55	Tin	23.0	0.6	11.8
Holmium	6.0	0.5	3.25	Tungsten	7.0	0.2	3.6
Iodine	0.1	0.1	0.1	Uranium	29.0	7.0	18.0
Lanthanum	620.0	22.0	321.0	Vanadium	480.0	28.0	254.0
Lead	69.0	3.0	36.0	Ytterbium	2.0	0.3	1.15
Lithium	250.0	16.0	133.0	Yttrium	350.0	7.0	178.5
Lutetium	0.3	0.1	0.2	Zinc	220.0	18.0	119.0
				Zirconium	1700.0	29.0	864.5

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1) Sage Point (Utah) Coal is one of the supply sources for PG&E's planned Fossil 1 & 2 project.
Source of data: PG&E Fossil 1 & 2 NOI.

projected (Fig. 25). Both in-state and out-of-state projects are included; with 1977 levels also shown for the existing plants (all out-of-state).[33] The high coal version of the utilities plans would produce about 10 million tons of waste per year in the year 2000; this would be evenly divided between Northern and Southern California.[34] With the nuclear version, coal plant waste production in the state would reach only about one million tons per year. Production of wastes by out-of-state coal-fired generation serving California would increase by a factor of three to four times in either case.

Typical landfill disposal of these wastes employs an effective depth of about six feet.[35] Therefore, the volumes of waste produced by California coal plant projects represent an annual land requirement of roughly 1000 acres by the year 2000 for the high coal scenario, compared with about 100 acres per year for the high nuclear plan. In the coal case, waste disposal requirements represent a significant portion (about one-fifth) of the total land requirements for implementing that plan (described in the land-use section). It may be possible to use deeper disposal basins (i.e., up to 30 feet deep) in some cases; they would reduce the land requirements identified above proportionately.

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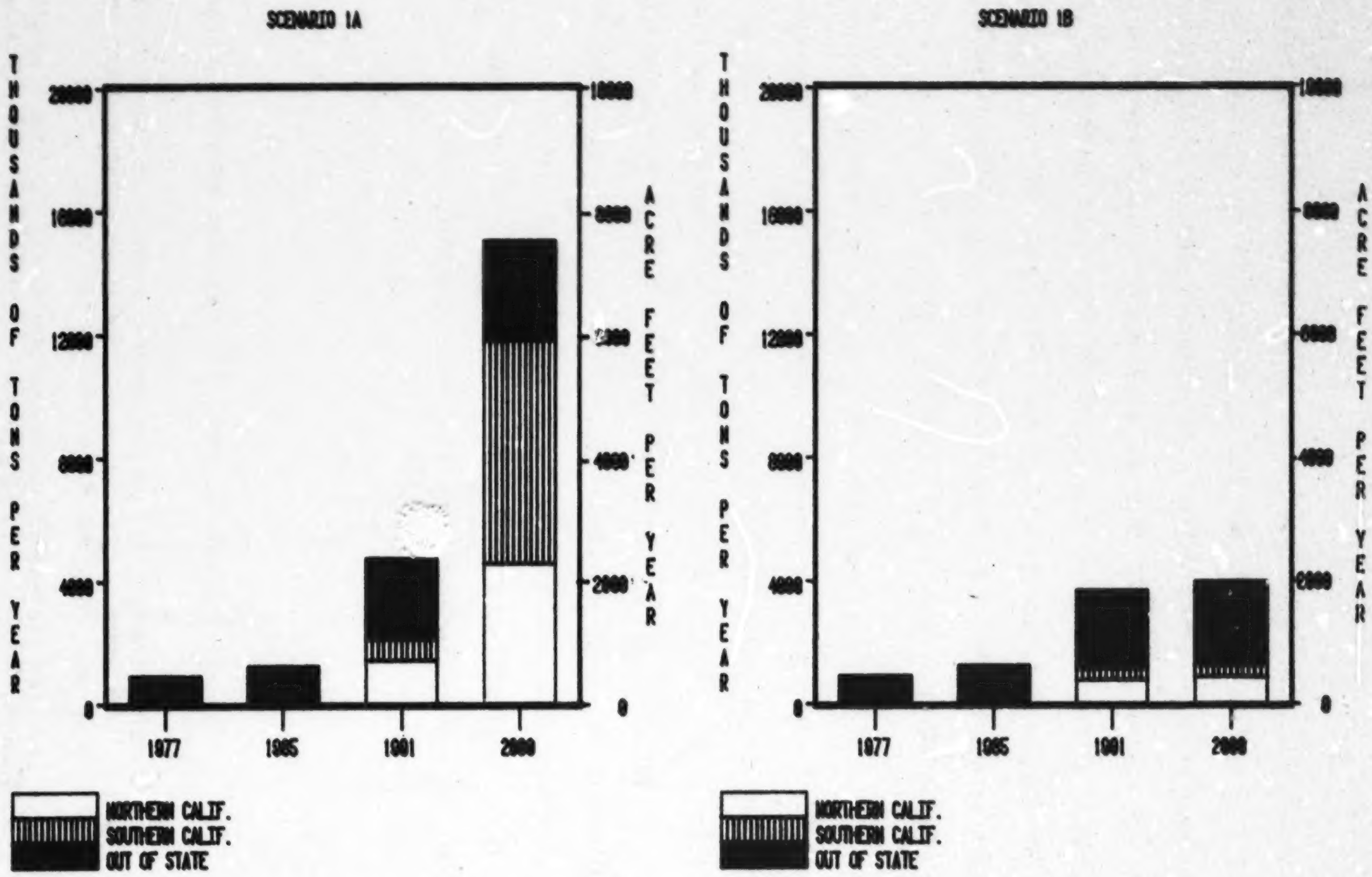
33. For out-of-state projects, only the capacity serving California is considered.

34. The division used for this purpose between Northern and Southern California is the Sixth Standard Parallel South, which forms the northern borders of San Luis Obispo, Kern, and San Bernardino Counties.

35. *Data Base for Standards/Regulations Development for Land Disposal of Flue Gas Cleaning Sludges*. SCS Engineers, Prepared for EPA, December 1977.

Figure 25

PROJECTED COAL PLANT SOLID WASTE PRODUCTION



Disposal

To date, the conventional method of disposing of coal plant wastes has been landfilling, usually without liners of impermeable material to prevent infiltration of liquids.[36] Water used to transport (sluice) the wastes to disposal basins has often been allowed to infiltrate to groundwater or to overflow as a discharge to surface water. More modern practices expected to be used by California coal plants use liner materials to effectively seal disposal basins, unless natural conditions are adequate to preclude infiltration. Sub-basin leakage detection and collection systems may also be used.

The first coal-fired power plant planned for construction in California, PG&E's Fossil 1 & 2, will use a stabilization process to combine the sludge from the flue gas desulfurization (FGD) system with the fly ash and bottom ash from the plant, prior to landfill disposal. Waste stabilization (or fixation) by blending and chemically interacting sludge and fly ash, sometimes with the use of chemical additives, is particularly advantageous in controlling the leaching of toxic substances from such materials.[37]

Several alternatives to conventional on-site landfill disposal are being studied for potential application to California coal plants. Remote site disposal possibilities include coal mine and quarry disposal. Disposing of solid waste at the source coal mine is a potential alternative, but the space available for disposal is dependent on the type of mining operation. The coal mine in Utah which will supply fuel for Fossil 1 & 2 will use the "longwall" method, which will preclude its use as a disposal site.[38]

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36. State-of-the-Art Scrubber Waste Disposal. W. Ellison, NUS Corporation, February 1978.

37. Review comments on Notice of Intent for PG&E's Proposed Coal Project, and Calculated Waste Disposal Volumes. Radian Corp., prepared for PG&E, October 1977.

38. Environmental Control Technologies for a Northern California Coal-Fired Power Plant. Acurex Corporation, prepared for CEC, June 1979.

Another waste management alternative involves the disposal of waste solids at the quarry that supplies the plants' FGD system with a sulfur dioxide scrubbing medium, usually lime or limestone. The major disadvantage of this option is the large quantities of solid wastes produced which will be about five times the lime or limestone used by the power plant. This will limit the potential of quarry sites to partial waste disposal.

As another alternative for reducing the potential for adverse environmental impacts, power plant solid wastes could be applied to a beneficial use. Currently, the main commercial uses for coal ashes are as fill material in manufacturing products such as concrete, building blocks, and roadbed stabilizer. The present reuse of ash from a Nevada power plant by a California cement manufacturer suggests favorable prospects for such reuse.[39]

Potential agricultural uses for coal ash are also being considered with major questions remaining as to the availability of plant nutrients and the liming potential of the material. The most promising potentially large-scale uses for scrubber sludge are as road base material and artificial aggregate, and as landfill or land reclamation materials if appropriately conditioned to prevent leaching.[40]

Assessment of the true potential of any of these solid waste reclamation/reuse alternatives for any given project will require more detailed studies of market prospects, cost effectiveness, and other factors. The chemical constituents of the wastes, which are of concern with conventional disposal, may also pose problems these applications.

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[39] CEC staff visit to Nevada Power Company's Reid Gardner Plant, from which fly ash is supplied to Kaiser Cement Company.

[40] Feasibility of Producing and Marketing By-Product Gypsum for SO_2 Emission Control at the Fossil-Fuel-Fired Power Plants. Tennessee Valley Authority, prepared for EPA, October 1978.

Two alternatives to the lime/limestone nonregenerative FGD system have shown potential for solving the sludge disposal problem. The first is a "dry" FGD process which produces a powdered product and not sludge. The second system uses a regenerative chemical process to recover the flue-gas sulfur dioxide in useful forms, such as sulfuric acid or elemental sulfur. Since regenerative processes do not produce sludge, only ash disposal is required at facilities using such systems. However, their effectiveness at removing sulfur dioxide has not been demonstrated to be comparable to the planned (nonregenerative) systems.

Remaining Problems and Issues

The Federal Resource Conservation and Recovery Act (RCRA) amends the Solid Waste Disposal Act by establishing a federal regulatory program to control the effects of hazardous wastes.[41] Under the initial implementation strategy, EPA's is primary emphasis is focused on identifying hazardous waste characteristics, listing hazardous wastes, and preparing guidelines for handling and disposition. The implementation of these guidelines depends on whether ash and/or FGD sludges are defined as general hazardous wastes under RCRA.

Enforcement of hazardous waste regulations would be delegated to individual states, if they so choose, through the establishment of a state hazardous waste program. In the State of California, if a waste is assessed to be hazardous, the Department of Health Services (DOHS) will be named lead agency and the permitting process will be handled entirely by local and state health services departments.

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41. The Impact of RCRA (Pl 94-850) on Utility Solid Wastes. Fred Hart Associates, prepared for EPRI, August 1978.

The solid waste generated by California coal plants will most likely be defined "hazardous" according to the DOHS, due to the constituents of the waste (excessive levels of barium, copper, and vanadium) and its physical characteristics (highly alkaline with natural pH of 12). Accordingly, these materials will have to be disposed of in either a Class I or Class II-1 disposal site.[42] The limited availability of Class I sites generally preclude their use as a disposal alternative; therefore, any site used to dispose of the coal-derived solid wastes must be classified as a Class II-1 disposal site. The specifications for a Class II-1 site require lining the site with a material designed to prevent the escape of leachate containing waste constituents.

Generally, state regulations will provide the primary requirements for disposal of plant wastes; RCRA compliance is expected to involve a minimum of additional measures. The main impact of RCRA will likely be felt by existing, out-of-state plants where it may be necessary to retrofit basin liners. Therefore, regulatory compliance for solid waste disposal practices by California coal plants now appears less of a problem than originally anticipated. However, several aspects of coal plant waste disposal are of continuing environmental concern. One issue involves the long-term effectiveness of available liner materials. At present, only minimal guarantees (5 years or less) can be obtained from manufacturers of artificial liners; the advantage of using these materials over using compacted clay or other conventional materials is somewhat in doubt.[43] Until a clearly preferable type of liner is developed, contingency measures in case of liner failure will be especially important.

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[42] Testimony of David L. Storm, Department of Health Services, presented on February 2, 1979 at the Fossil 1 & 2 NOI Hearing before the CEC. Class I sites are those where natural conditions prevent pollutants from reaching usable waters. Class II-1 sites are allowed to use artificial barrier to prevent migration of waste constituents. These requirements are set forth in Subchapter 15, Chapter 3, Title 23 of the California Administrative Code.

The restoration and reclamation of land after waste disposal is another major concern of landfill disposal. Certain waste management techniques are intended to assure permanent protection of the environment after a waste disposal site has been abandoned. These techniques include closure procedures and extensive monitoring programs. Selection of a specific site will also affect the potential use of the land after closure.

Beneficial reuse appears to be an attractive option for coal plant wastes. However, it appears unlikely that the need for landfill disposal can be eliminated entirely, since markets for the quantities of ash or sludge which will be produced by the planned facilities are not yet apparent. Additional exploration of potential reuse schemes, and perhaps subsidies or other incentives for their application, will be necessary before a significant amount of conventional disposal can be displaced by such practices.

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[43] Testimony of Chris Olivera, CEC, at the Fossil 1 & 2 NOI Hearing before the CEC, February 2, 1979.